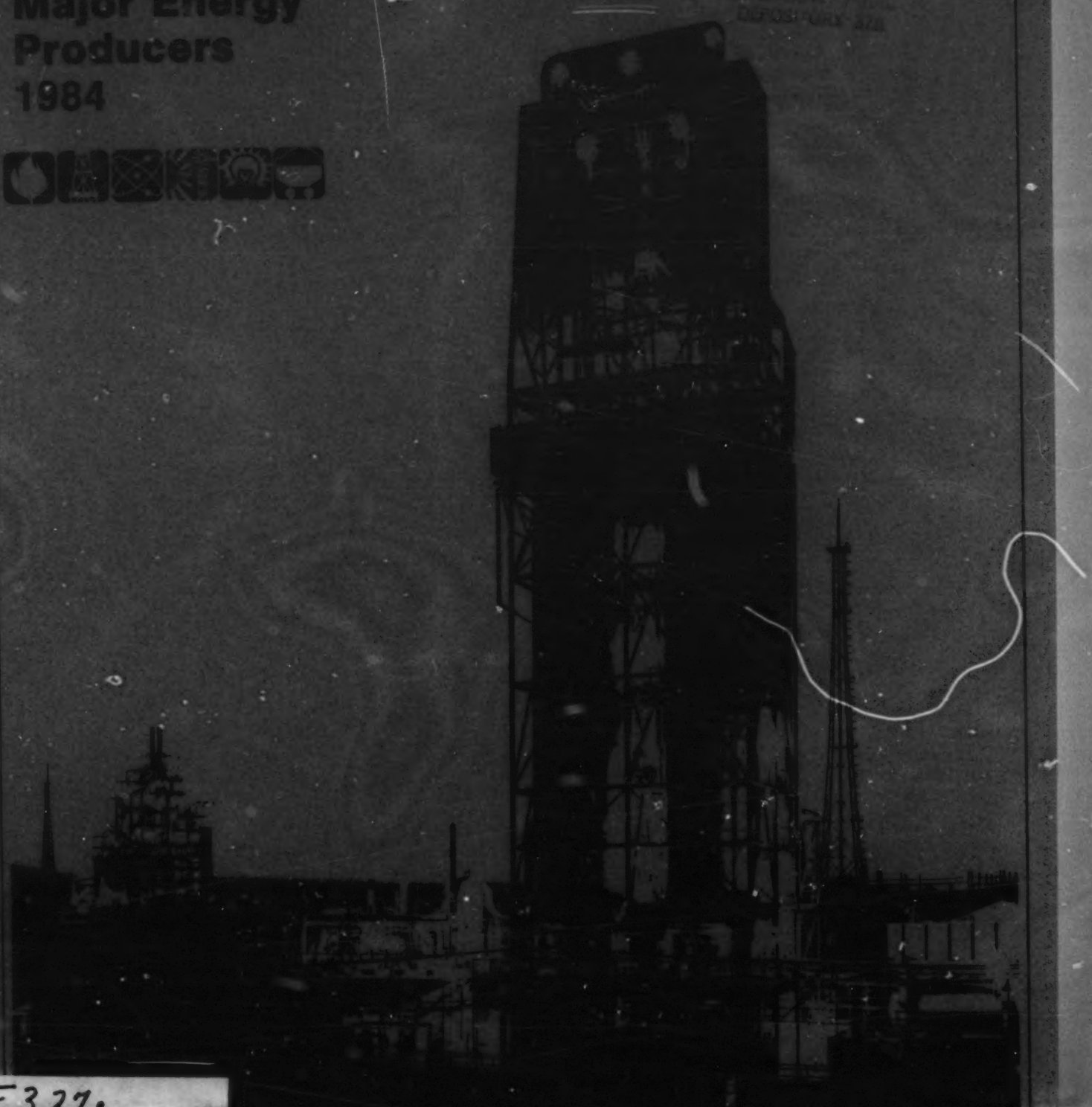
984

DOE/EIA-0206 (84)

Performance Profiles of Major Energy Producers 1984

Energy Information Administration
Washington, D.C.

NEWARK PUBLIC LIBRARY
FEB 1 0000
U.S. GOVT.
DEPOSITORY



E 3.37:

This publication is available from the Superintendent of Documents, U.S. Government Printing Office (GPO). Ordering information and purchase of this and other Energy Information Administration (EIA) publications may be obtained from the GPO or the EIA's National Energy Information Center (NEIC). Questions on energy statistics should be directed to the NEIC. Addresses and telephone numbers appear below.

National Energy Information Center, EI-20
Energy Information Administration
Forrestal Building
Room 1F-048
Washington, D.C. 20585
(202) 252-8800

Superintendent of Documents
U.S. Government Printing Office
Washington, D.C. 20402
(202) 783-3238

Released for Printing January 21, 1986

Performance Profiles of Major Energy Producers 1984

Energy Information Administration
Office of Energy Markets and End Use
U.S. Department of Energy
Washington, D C 20585

DOE/EIA-0206(84)
Distribution Category UC-98

READEX FICHE best copy available

This report was prepared by the Energy Information Administration, the independent statistical and analytical agency within the Department of Energy. The information contained herein should not be construed as advocating or necessarily reflecting any policy position of the Department of Energy or any other organization.

Contacts

Performance Profiles of Major Energy Producers, 1984 was prepared in the Economics and Statistics Division, Office of Energy Markets and End Use, Energy Information Administration, U.S. Department of Energy, under the direction of Arthur T. Andersen (202) 252-1444.

Specific information concerning the preparation of this document and technical information concerning the Form EIA-28 may be obtained from Jon A. Rasmussen (202) 252-1449.

Preface

Pursuant to Section 205(h)(2) of the Department of Energy Organization Act, the Energy Information Administration, through Form EIA-28, has collected financial information and other measures of energy-related business efforts and results for 25 (the merger of Cities Service with Occidental Petroleum in 1982 reduced the number of reporting companies from 26 to 25 beginning in 1983) major energy companies, on a uniform, segmented basis. Comparability of information across energy lines of business is unique to this reporting system. For example, petroleum activities can be compared to activities in other energy lines of business or nonenergy areas, and domestic activities can be contrasted to foreign activities. The purpose of this publication is to examine year-to-year developments in the operations of the 25 major U.S. energy-producing companies on a corporate level, by major line of energy business, and by major functions within each line of business. This report presents data collected on Form EIA-28 for calendar year 1984. Although the focus is on developments in 1984, important trends over the 1974-84 period are also featured.

Economic performance, in financial and physical dimensions, continues to serve as a significant factor in evaluating past decisions and guiding future options in the development and supply of energy resources. The information contained in this report is intended to promote an understanding and a critical review of the possible motivations and apparent consequences of investment decisions by some of the largest corporations in the energy industry. The information is intended for use by the Congress, Government agencies, industry analysts, and the public.

Contents

	Page
Executive Summary	xvii
1. Introduction	1
2. Key Financial Trends	7
Trends in Sales and Income	9
Overall Corporate Results	9
Line-of-Business Results	12
Investment Trends	17
Overall Investment	17
Investment Patterns by Lines of Business	17
Mergers, Acquisitions, Divestitures, and Patterns of Diversification in 1984	20
Mergers	20
Other Acquisitions	22
Divestitures	24
Diversification Patterns	25
Funds Availability and Cash Flow	28
3. Taxation	33
Income Taxes	35
Domestic	37
Foreign	38
Effective Tax Rates	38
Deferred Income Taxes	42
Non-income Taxes	45
4. Domestic Petroleum Developments	51
Oil and Gas Production	55
Sales and Income	55
Upstream Petroleum Investments	58
Refining and Marketing	61
Financial and Operating Results	61
Refinery Configuration	62
Refined Product Marketing	67
5. Domestic Petroleum Resource Development	73
Expenditures on Exploration and Development	75
Drilling Activity	76
Oil Versus Gas Well Drilling	80
Lease Acreage	81
Reserves, Reserve Additions, and Production	85
Finding Costs, Lifting Costs, and Profit Margins	90

Page

6. Foreign Petroleum Developments 95
Income and Investment in Foreign Petroleum 97
Income 97
Investment 99
Operating Results 103
Production and Resource Development 103
Refining 108
Patterns of U.S. and FRS Companies' Imports 113

7. Coal, Nuclear, and Other Energy 121
Coal 123
Nuclear 127
Other Energy 128
Research and Development Expenditures 130

Glossary 133

Appendices

A. General Structure of the Reporting Format of the Financial Reporting System Form EIA-28 151

B. Selection of FRS Reporting Companies 157

C. Data Quality Assurance Program 161

D. Financial Analysis Guide 167

E. Accounting Practices 173

F. Statistical Disclosure Avoidance Procedures 185

G. Detailed Statistical Tables 189

H. Major Energy Provisions of the Tax Reform Act of 1984 247

Tables

		Page
1.	A Comparison of Selected Financial Items for FRS Companies and the S&P 400, 1984 and Percent Change from 1983	10
2.	Allocated Revenues, Income, and Investment for FRS Companies, 1984	10
3.	Line-of-Business Contributions to Net Income for FRS Companies, 1983-1984	16
4.	Additions to Investment in Place for FRS Companies, 1983-1984	18
5.	Sources of Change in Net Investment in Place for FRS Companies, 1984	21
6.	U.S. Oil and Natural Gas Reserve Shares for FRS Companies (Net Ownership Basis), 1983 and 1984	22
7.	Estimated Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 1984	23
8.	Book Value of Disposals of PP&E for FRS Companies, 1978-1984	24
9.	Major Asset Disposals of FRS Companies, 1984	25
10.	Distribution of Net PP&E by Line of Business for FRS Companies, 1976-1984	26
11.	Effect of Mergers on Distribution of Net PP&E by Line of Business for FRS Companies, 1983-1984	28
12.	Components of Sources and Uses of Funds for FRS Companies, 1981-1984	30
13.	Income Tax Expense, Pre-Tax Income, and Tax Shares for FRS Companies, Selected Years, 1974-1984	37
14.	Composition of Income Tax Expense for FRS Companies, Selected Years, 1974 to 1984	40
15.	Deferred, Current, and Total Income Taxes, 1981-1984	42
16.	Sources of Deferred Income Taxes for FRS Companies, 1981-1984	43
17.	Deferred Income Taxes and Funds from Operations, 1981-1984	45
18.	Additional Domestic Tax Liabilities of FRS Companies, 1981-1984	46
19.	Crude Oil Windfall Profit Tax Liabilities of FRS Companies and U.S. Industry, 1980-1984	46

Page

20. Domestic Petroleum Contribution to Net Income for FRS Companies Ranked by Total Energy Assets, 1981-1984 53

21. Average Prices, Sales, and Production in Domestic Oil and Gas for FRS Companies, 1981-1984 57

22. Components of Revenues and Costs in Domestic Oil and Gas Production for FRS Companies, 1981-1984 58

23. Additions to PP&E in Domestic Petroleum for FRS Companies Ranked by Total Energy Assets, 1983-1984 59

24. Sales, Expenses, and Income in Domestic Refining/Marketing for FRS Companies, 1982-1984 61

25. Refineries Shut Down Since January 1, 1981, for FRS Companies and Domestic Industry 63

26. Refining Statistics for FRS Companies Ranked by Total Energy Assets and Domestic Industry, 1981-1984 64

27. Domestic Refinery Configuration for FRS Companies Ranked by Total Energy Assets and Domestic Industry, 1983 and 1984 66

28. Changes in FRS Companies' Gasoline Distribution, Selected Years, 1977-1984 68

29. Refined Product Marketing Expenses for FRS Companies Ranked by Total Energy Assets, 1982-1984 69

30. Domestic Exploration and Development Expenditures Compared to Various Measures of Economic Activity, 1983-1984 76

31. Measures of Drilling and Exploratory Activity for FRS Companies and Domestic Industry, 1983-1984 77

32. Comparison of FRS and Non-FRS Companies' Drilling Activities, 1984 79

33. Oil and Gas Well Completions by FRS Companies and Domestic Industry, 1983-1984 80

34. Domestic Net Petroleum Acreage Under Lease for FRS Companies and Domestic Industry, 1984 and Percent Change from 1983 83

35. Expenditures by FRS Companies for Undeveloped Acreage Compared to OCS Leasing Activity for Domestic Industry, 1980-1984 83

36. Comparison of FRS and Industry Reserves and Production, 1984 85

37. Composition of Reserve Changes for FRS Companies, 1980-1984 90

Page

38. Percent Distribution of Domestic Gross Reserve Additions for FRS Companies, 1980-1984 90

39. Ratio of Domestic Exploration and Development Expenditures to Reserve Additions for FRS Companies, 1982-1984 91

40. Petroleum Lifting Costs for FRS Companies, 1978-1984 92

41. Fraction of Current and Previous Years' Exploration and Development Expenditures Attributed to Current Reserve Additions 92

42. Before and After Tax Revenue, Costs, and Profit Margins for FRS Companies, 1982-1984 93

43. Foreign Petroleum Contribution to Net Income for FRS Companies Ranked by Total Energy Assets, 1981-1984 98

44. Additions to PP&E in Foreign Petroleum for FRS Companies Ranked by Total Energy Assets, 1983-1984 101

45. Foreign Petroleum Exploration, Development, Reserves, and Production Statistics by Geographical Area for FRS Companies, 1984 and Percent Change from 1983 104

46. Foreign Refinery Output, Average Capacity, and Capacity Utilization for FRS Companies and Foreign Industry, 1981-1984 ... 108

47. Foreign Refinery Configuration for FRS Companies and Foreign Industry, 1983 and 1984 110

48. Sources of U.S. Crude Oil and Natural Gas Liquids Imports for FRS Companies, 1977-1984 116

49. Sources of U.S. Petroleum Product Imports for FRS Companies, 1977-1984 118

50. Operating and Financial Items in Coal for FRS Companies and Domestic Industry, 1981-1984 124

51. Production, Dispositions, and Prices of Coal for FRS Companies and Domestic Industry, 1981-1984 125

52. Operating and Financial Items in Nuclear for FRS Companies and Domestic Industry, 1981-1984 128

53. Investment and Income in Other Energy for FRS Companies, 1981-1984 129

54. Distribution of Net PP&E in Other Energy for FRS Companies, Selected Years, 1975-1984 130

Page

55. Worldwide Research and Development Expenditures by FRS Companies, 1981-1984 131

Detailed Statistical Tables

Appendix G

G1. Selected Domestic Operating Statistics for FRS Companies and Total Industry, 1983 and 1984 191

G2. A Comparison of Selected Financial Items for FRS Companies and the S&P 400, 1984 and Percent Change from 1983 192

G3. Selected Financial Items for FRS Companies Ranked by Total Assets, 1984 and Percent Change from 1983 193

G4. A Comparison of Balance Sheet Items for FRS Companies and the S&P 400, 1984 and Percent Change from 1983 194

G5. Balance Sheet Items for FRS Companies Ranked by Total Assets, 1984 and Percent Change from 1983 195

G6. A Comparison of Key Financial Indicators, Selected Performance Measures, and Patterns of Finance for FRS Companies and the S&P 400, 1982 to 1984 196

G7. Financial Indicators for FRS Companies Ranked by Total Assets, 1984 197

G8. Distribution of Fixed Investment for FRS Companies, Domestic and Foreign, 1984 198

G9. Distribution of Selected Financial Items for FRS Companies Ranked by Total Assets, 1984 199

G10. Effective Tax Rates for FRS Companies Ranked by Total Assets and S&P 400, 1984 200

G11. Worldwide Income Taxes for FRS Companies, 1983 and 1984 201

G12. U.S. Federal Income Taxes for FRS Companies, 1983 and 1984 202

G13. Domestic Taxes Other than Income Taxes for FRS Companies, 1984 and Percent Change from 1983 203

G14. Contributions to Income and Investment by Lines of Business for FRS Companies, 1984 and Percent Change from 1983 204

Page

G15. Contribution to Income and Investment Patterns in Nonenergy Segments for FRS Companies, 1984 and Percent Change from 1983 205

G16. Effective Income Tax Rates by Lines of Business for FRS Companies, 1984 206

G17. Income and Investment by Lines of Business for FRS Companies Ranked by Total Assets, 1984 and Percent Change from 1983 207

G18. Performance Indicators by Lines of Business for FRS Companies Ranked by Total Assets, 1982 to 1984 208

G19. Contributions to Income and Investment Patterns in Worldwide Petroleum for FRS Companies, 1984 and Percent Change from 1983 209

G20. Income and Investment Patterns in Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1984 and Percent Change from 1983 210

G21. Performance Indicators in Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1982 to 1984 211

G22. Contributions to Income and Investment Patterns by Petroleum Segments for FRS Companies, 1984 and Percent Change from 1983 212

G23. Effective Income Tax Rates Within the Petroleum Segments for FRS Companies, 1984 and Percent Change from 1983 213

G24. Income and Investment Patterns by Petroleum Segments for FRS Companies Ranked by Total Energy Assets, 1984 and Percent Change from 1983 214

G25. Size Distribution of Income and Investment Within Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1982 to 1984 215

G26. Performance Indicators by Petroleum Segments for FRS Companies Ranked by Total Energy Assets, 1982 to 1984 216

G27. Expenditures for Domestic and Foreign Petroleum for FRS Companies, 1983 and 1984 217

G28. Petroleum Exploration and Development Expenditures for FRS Companies, Domestic and Foreign, 1984 and Percent Change from 1983 218

Page

G29. Total Exploratory and Development Wells Drilled in the United States for FRS Companies and Domestic Industry, 1983 and 1984 219

G30. Domestic Exploration and Development Drilling and Equipping Costs for FRS Companies and Domestic Industry, 1983 and 1984 220

G31. Completed Well Costs, Oil, Gas, and Dry, for FRS Companies and Domestic Industry, 1983 and 1984 221

G32. Completed Well Costs, Oil, Gas, and Dry, Onshore and Offshore, for FRS Companies, 1983 and 1984 222

G33. Domestic Net Petroleum Acreage for FRS Companies Ranked by Total Energy Assets and Total Industry, 1984 and Percent Change from 1983 223

G34. Domestic Reserve Additions, Exploration and Development Expenditures, and Expenditures per Barrel of Reserve Additions for FRS Companies Ranked by Total Energy Assets, and Domestic Industry, 1982 to 1984 224

G35. Domestic Net Ownership Interest Petroleum Reserves and Production for FRS Companies and Domestic Industry, 1984 225

G36. Foreign Crude Oil and Natural Gas Liquids Production for FRS Companies and Foreign Industry, 1984 and Percent Change from 1983 226

G37. Distribution of Foreign Exploration and Development Expenditures for FRS Companies Ranked by Total Energy Assets, 1984 and Percent Change from 1983 227

G38. Foreign Exploration and Development Wells Completed for FRS Companies and Foreign Industry, 1984 and Percent Change from 1983 228

G39. Foreign Crude Oil and Natural Gas Liquids Reserve Interest for FRS Companies, 1984 and Percent Change from 1983 229

G40. Sources of Domestic Bituminous Coal and Lignite Supply for FRS Companies and Domestic Industry, 1983 and 1984 230

G41. Sources of Domestic Bituminous Coal and Lignite Production, by Region and Mining Method, for FRS Companies and Domestic Industry, 1984 and Percent Change from 1983 231

Page

G42. Domestic Dispositions of Bituminous Coal and Lignite for FRS Companies and Domestic Industry, 1984 and Percent Change from 1983 232

G43. Domestic Uranium Production and Estimated Uranium Reserves for FRS Companies and Domestic Industry, 1983 and 1984 233

G44. Domestic Uranium Resource Development Measures and Drilling Expenditures for FRS Companies and Domestic Industry, 1984 and Percent Change from 1983 234

G45. Other Energy: Patterns of Income and Investment for FRS Companies, 1983 and 1984 235

G46. Uses of Research and Development Funds for FRS Companies, 1984 and Percent Change from 1983 236

G47. Sources of Research and Development (R&D) Funds for FRS Companies Ranked by Total Energy Assets, 1984 and Percent Change from 1983 237

G48. Domestic and Foreign Oil Raw Materials Balance for FRS Companies Ranked by Total Energy Assets, 1982 to 1984 238

G49. Domestic Refinery Output, and Refinery Capacity Statistics, for FRS Companies Ranked by Total Energy Assets and Domestic Industry, 1983 and 1984 239

G50. Foreign Refinery Output, and Refinery Capacity Statistics, for FRS Companies Ranked by Total Energy Assets and Foreign Industry, 1983 and 1984 240

G51. Domestic Refined Petroleum Product Sales Volumes and Values, by Distribution Channel for FRS Companies, 1983 and 1984 241

G52. Sales of Domestic Refined Petroleum Products, by Volume and Price, for FRS Companies, 1983 and 1984 242

G53. Domestic Gasoline Sales for FRS Companies Ranked by Total Energy Assets, 1983 and 1984 243

G54. Domestic Refining/Marketing Revenues and Costs for FRS Companies, 1982 to 1984 244

G55. Annual Percent Change in Net Property, Plant, and Equipment in Domestic Refining/Marketing Compared to Other Domestic Petroleum for FRS Companies Ranked by Total Energy Assets, 1981 to 1984 245

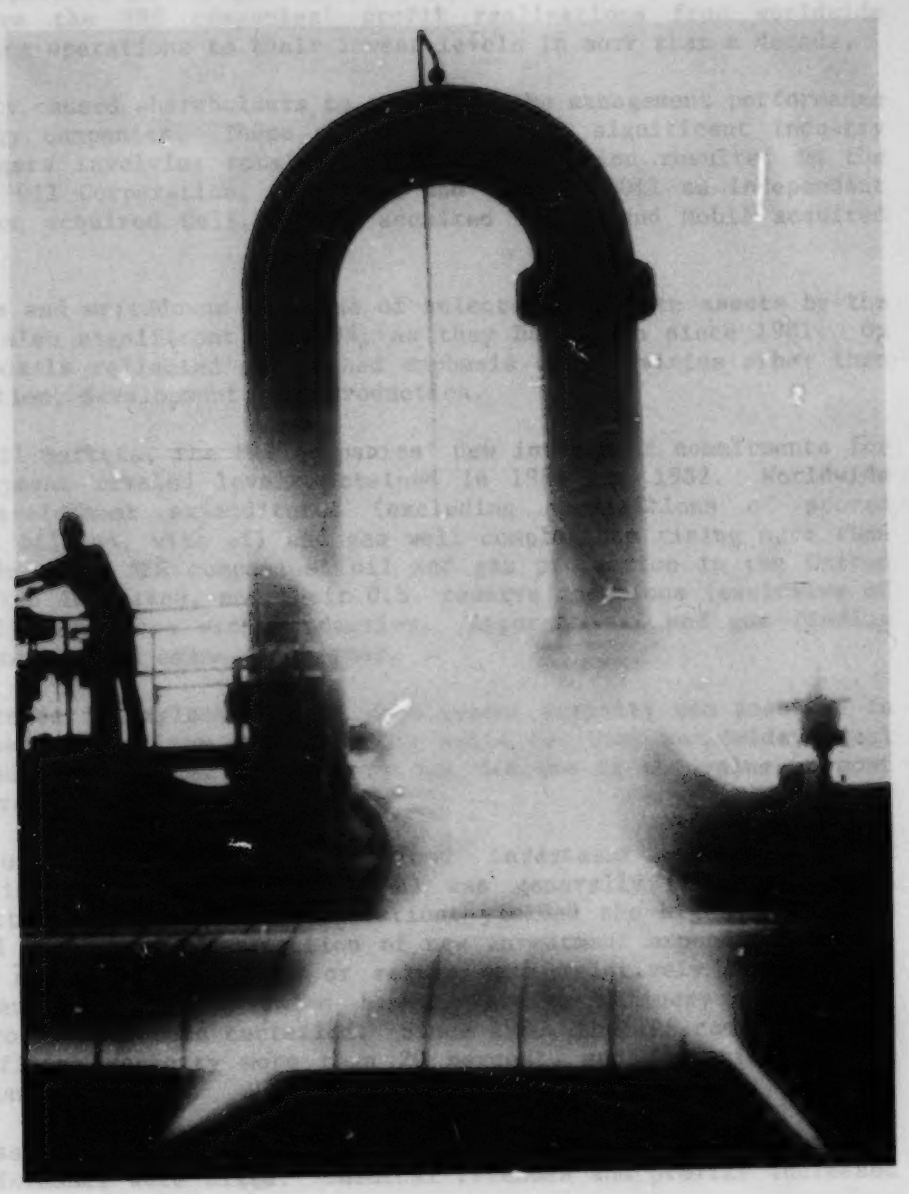
Figures

		Page
1.	Selected Domestic Operating Statistics, 1984	4
2.	Selected Performance Measures for FRS Companies and the S&P 400, 1973-1984	11
3.	Operating Revenues by Line of Business for FRS Companies, 1981-1984	13
4.	Rates of Return by Line of Business for FRS Companies, 1978-1984	15
5.	Additions to PP&E and Value of Acquisitions and Mergers for FRS Companies, 1975-1984	19
6.	Distribution of Net PP&E by Line of Business for FRS Companies, Selected Years	27
7.	Total Funds from Operations and Net Income for FRS Companies, 1978-1984	29
8.	Worldwide Tax Liabilities of FRS Companies, 1983-1984	36
9.	Income Tax Shares in Worldwide Pre-Tax Income, FRS Companies, 1975-1984	39
10.	Worldwide Effective Income Tax Rates for FRS Companies and S&P 400, 1975-1984	41
11.	Sale Price, Adjusted Price, and Windfall Profit per Barrel for U.S. Industry, 1980-1984	48
12.	Profit Rates in Domestic Petroleum Segments for FRS Companies, 1977-1984	54
13.	Net Income as a Percent of Stockholders' Equity for Publicly Traded Non-FRS Oil and Gas Producers and Refiner/Marketers, 1978-1984	56
14.	Additions to PP&E in Domestic Petroleum for FRS Companies, 1975-1984	60
15.	Refinery Capacity and Crude Oil inputs for Domestic Industry, 1975-1984	65
16.	Marketing Expenses per Barrel of Product for FRS Companies, 1981-1984	70
17.	Domestic Exploration and Development Well Completions for FRS and Non-FRS Companies, 1978-1984	78

		Page
18.	Gas Wells Completed as a Percent of Oil Wells Completed for FRS Companies and Domestic Industry, 1975-1984	82
19.	Domestic Onshore and Offshore Undeveloped Acreage Holdings for FRS Companies, 1975-1984	84
20.	Domestic Crude Oil, NGL, and Dry Natural Gas Reserves for FRS and Non-FRS Companies, 1978-1984	86
21.	Domestic Crude Oil, NGL, and Dry Natural Gas Gross Reserve Additions for FRS and Non-FRS Companies, 1978-1984	87
22.	Domestic Crude Oil, NGL, and Dry Natural Gas Production for FRS and Domestic Industry, 1975-1984	89
23.	Profit Rates in Foreign Petroleum Segments for FRS Companies, 1978-1984	100
24.	Additions to Net Investment in Place in Foreign Petroleum for FRS Companies, 1978-1984	102
25.	Geographical Composition of FRS Companies' Foreign Crude Oil Production, 1975-1984	105
26.	Foreign Crude Access for FRS Companies, 1978-1984	106
27.	Foreign Exploration and Development Expenditures for FRS Companies, 1977-1984	107
28.	Distribution of Foreign Distillation Capacity, 1981-1984	109
29.	Distribution of Foreign Gasoline Capacity, 1981-1984	111
30.	Distribution of Foreign Heavy/Sour Capacity, 1981-1984	112
31.	Net Domestic Crude Oil and NGL Imports for FRS Companies Ranked by Total Energy Assets, 1978-1984	114
32.	Sources of FRS Crude Oil Imports, 1980-1984	115
33.	Petroleum Product Imports for FRS Companies Ranked by Total Energy Assets, 1980-1984	117
34.	Sources of Petroleum Product Imports for FRS Companies, 1980-1984	119
35.	Geographic Composition of Domestic Bituminous Coal and Lignite Production for FRS Companies, 1977-1984	126

Page

Executive Summary



Sunrise at Meter Station

Executive Summary

Executive Summary

Net income of the 25 major energy companies reporting to the Financial Reporting System (FRS) declined in 1984 even as economic expansion in the United States proceeded at rates unmatched for more than two decades. While other large industrial companies realized profit gains averaging more than 20 percent, the FRS companies reported a 3-percent decline. As a consequence, their return on equity was exceeded by that of large industrial corporations overall for the first time since 1978.

Petroleum product market developments accounted for this relatively poor performance. Although U.S. petroleum product demand rose in 1984, the increase was small and overall demand was still nearly 15 percent below levels attained in 1979. In addition, product prices generally declined in 1984. This decline in product prices drove the FRS companies' profit realizations from worldwide refining and marketing operations to their lowest levels in more than a decade.

Lagging profitability caused shareholders to challenge the management performance of some major energy companies. These challenges led to significant industry restructuring. Mergers involving total assets of $30 billion resulted in the elimination of Gulf Oil Corporation, Getty Oil and Superior Oil as independent enterprises. Chevron acquired Gulf, Texaco acquired Getty, and Mobil acquired Superior.

Partial divestitures and writedowns in value of selected corporate assets by the FRS companies were also significant in 1984, as they have been since 1981. On balance, asset disposals reflected diminished emphasis on activities other than oil and gas exploration, development, and production.

Despite uncertain oil markets, the FRS companies' new investment commitments for oil and gas development rivaled levels attained in 1981 and 1982. Worldwide exploration and development expenditures (excluding acquisitions of proved acreage) were up $1 billion, with oil and gas well completions rising more than 25 percent worldwide. The FRS companies' oil and gas production in the United States and abroad also increased, and their U.S. reserve additions (exclusive of net purchase) nearly kept pace with production. Apparent oil and gas finding costs declined for the second consecutive year.

The sharp real increase in exploration and development activity was possible in part because the cost of drilling and equipping wells declined worldwide. Real cost declines abroad were further assisted by the decline in the value of most foreign currencies relative to the dollar.

The composition of the FRS companies' new investment commitments by line of business in 1984 (excluding mergers) was generally consistent with realized profit patterns. The upstream operations yielded the highest rates of return and received the greatest allocation of new investment expenditures. In contrast, refining and marketing rates of return were relatively low and new investment commitments have been scaled back. Foreign refinery operations, particularly in Europe, have been curtailed. Since 1980, the FRS companies have reduced foreign refining capacity more than 20 percent, and domestic refining capacity by more than 15 percent.

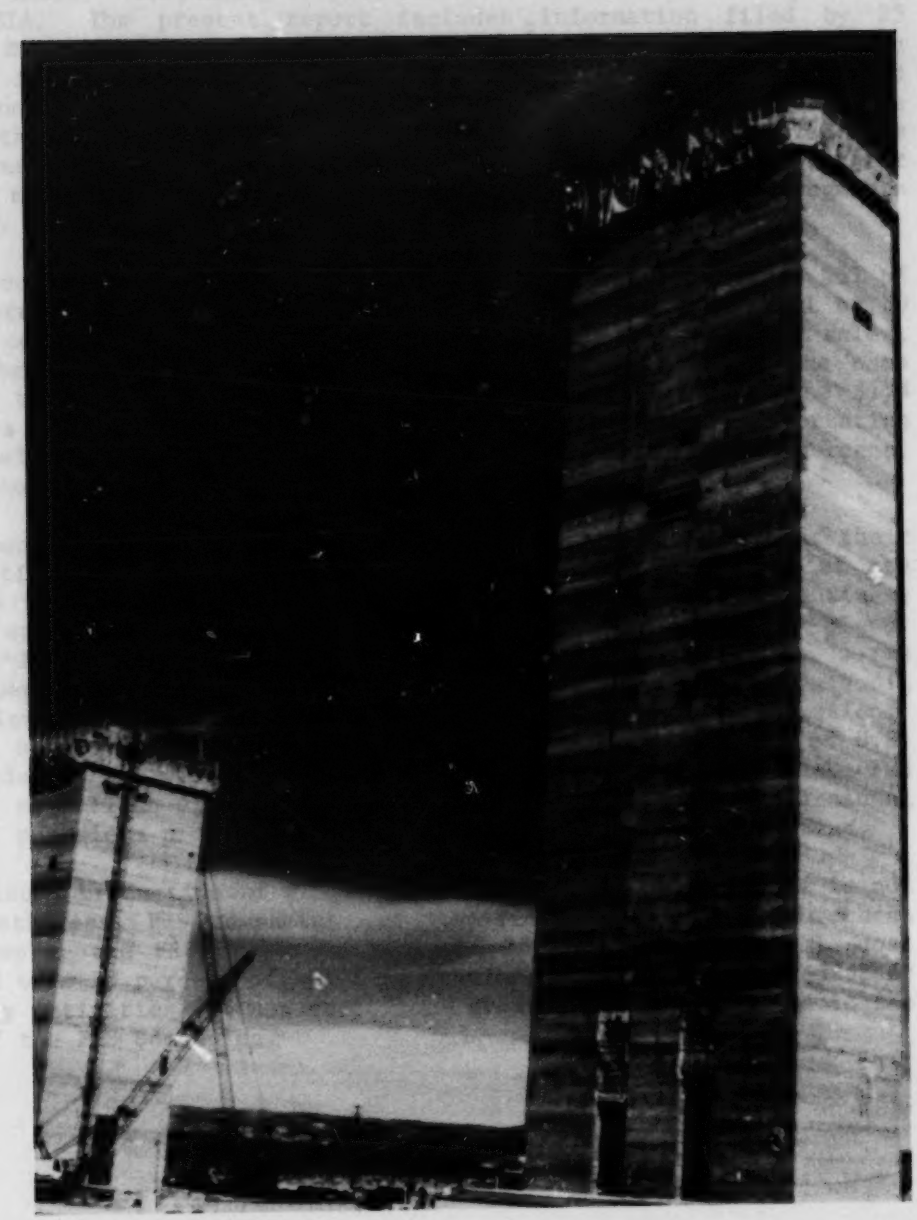
In lines of business outside of petroleum, the FRS companies' revenues, profit, and investment performance were mixed. Chemical revenues and profits increased

in pace with overall economic activity in 1984. Coal operations also yielded higher returns. Profits from other nonenergy lines of business including retailing, office equipment, manufacturing, mineral mining, and insurance continued to improve somewhat relative to those in 1983, although several FRS companies announced discontinuation of some nonenergy businesses.

Nonconventional energy development activities reflect further cutbacks in oil shale and coal gasification/liquefaction projects. In contrast, FRS companies' investments in geothermal operations rose significantly. In 1984, for the first time since 1974 (the first year of FRS data collection), new investment commitments for renewable energy activities accounted for more than half of all investments in nonconventional energy projects.

Chapter 1

Introduction



1. Introduction

The energy industry has reacted to many unsettling forces during the past decade. Oil supply interruptions resulting from military conflicts and political upheaval, unprecedented oil price increases, energy price controls, special energy taxes and subsidies, conservation measures, energy-aggravated recessions and, most recently, oil price reductions, have buffeted the industry. To analyze the extent to which these and other developments have affected the energy industry's financial and operating performance, strategies, and industry structure, the Energy Information Administration (EIA) maintains the Financial Reporting System (FRS).[1]

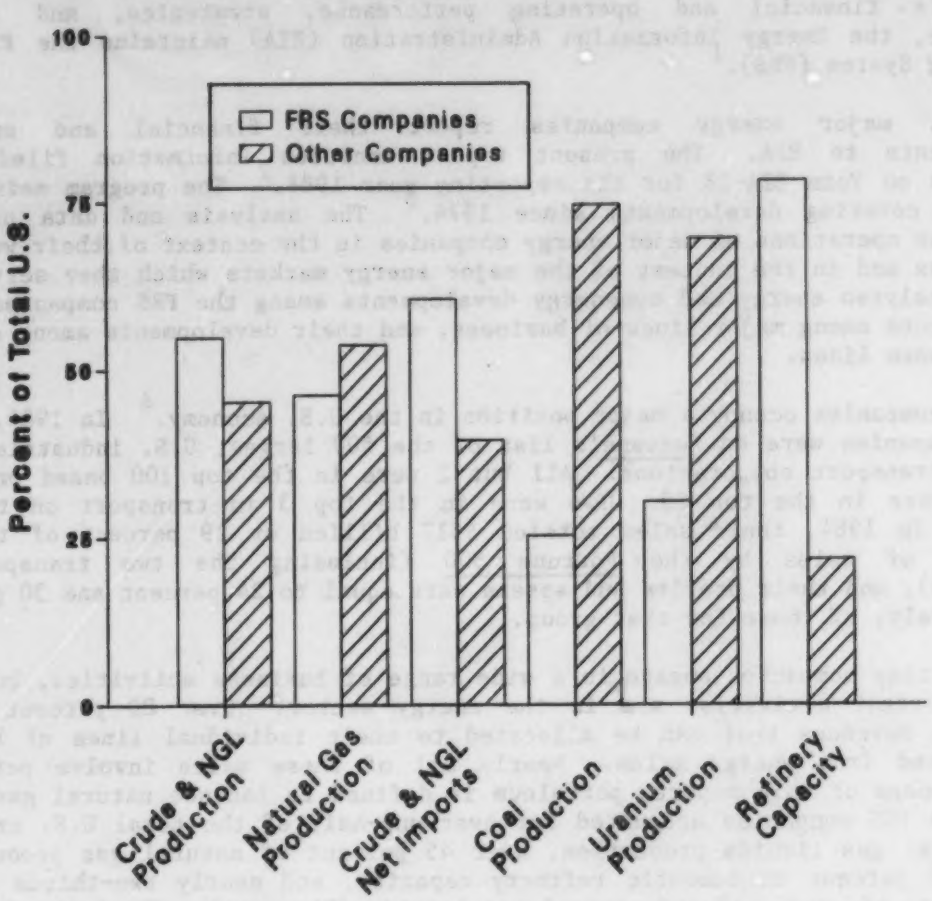
Annually, major energy companies report their financial and operating developments to EIA. The present report includes information filed by 25 companies on Form EIA-28 for the reporting year 1984.[2] The program maintains a database covering developments since 1974.[3] The analysis and data presented depict the operations of major energy companies in the context of their worldwide operations and in the context of the major energy markets which they serve. The report analyzes energy and nonenergy developments among the FRS companies, their developments among major lines of business, and their developments among segments within those lines.

The FRS companies occupy a major position in the U.S. economy.[4] In 1984, all of these companies were on Fortune's list of the 500 largest U.S. industrial or 50 largest transport corporations. All but 2 were in the top 100 based on sales, and 13 were in the top 20. Two were in the top 3 in transport on the same basis.[5] In 1984, their sales totaled $517 billion or 29 percent of the $1.8 trillion of sales by the Fortune 500 (including the two transportation companies), and their profits and assets were equal to 24 percent and 30 percent, respectively, of those for that group.

The reporting companies engage in a wide range of business activities, but their most important activities are in the energy sector. Over 80 percent of the operating revenues that can be allocated to their individual lines of business are derived from energy sales. Nearly all of these sales involve petroleum. (For purposes of this report, petroleum is defined to include natural gas.[6]) In 1984, the FRS companies accounted for over one-half of the total U.S. crude oil and natural gas liquids production, over 45 percent of natural gas production,[7] nearly 80 percent of domestic refinery capacity, and nearly two-thirds of U.S. net imports of crude oil and natural gas liquids (Figure 1). The bulk of the FRS companies' assets, as well as of their new investments, are devoted to sustaining various aspects of petroleum production, processing, transport, and marketing.

Relative to petroleum, production of nonpetroleum energy by FRS companies is not very great. Nonetheless, FRS companies are significant participants in these markets. For example, the FRS companies produced 25 percent of all U.S. coal output in 1984 and over 30 percent of all U.S. uranium. However, these and other nonpetroleum energy activities did not contribute greatly in the aggregate to the overall profits of the FRS companies.

Figure 1. Selected Domestic Operation Statistics, 1984



Source: See Table G1, Appendix G

Footnotes to Chapter 1

[1]Public Law 95-91, August 4, 1977, the Department of Energy Organization Act, 91 Stat. 573.

[2]The 25 companies included in the FRS are the following: Amerada Hess, American Petrofina, Ashland Oil, Atlantic Richfield, Burlington Northern, Chevron Corporation (formerly Standard Oil Company of California), Coastal Corporation, Du Pont, Exxon, Getty Oil, Gulf Oil, Kerr-McGee, Mobil Corporation, Occidental Petroleum, Phillips Petroleum, Shell Oil, Standard Oil Company (Indiana), Standard Oil Company (Ohio), Sun Company, Superior Oil, Tenneco, Texaco, Unocal, Union Pacific, and U.S. Steel. Prior to 1983 the reporting group included 26 companies. Conoco and Marathon were replaced by Du Pont and U.S. Steel, due to the merger of the former companies with the latter companies, respectively, beginning in 1982. Although Occidental acquired Cities Service in 1982, separate financial reports were available for 1982, so each company continued to be treated as a separate FRS company until 1983. In 1984 three more intragroup mergers occurred: (1) Chevron acquired Gulf Oil, (2) Mobil acquired Superior Oil, and (3) Texaco acquired Getty Oil. Since financial reports for 1984 were available for the three acquired companies, they are treated as separate companies for 1984 and prior years. Information for the FRS is derived from an extensive database provided by Form EIA-28 filed by the 25 companies (see Appendix B for a discussion of the selection of the FRS reporting group).

[3]Additionally, a special postembargo report covering the period 1974-1980 was issued. See Energy Information Administration, U.S. Department of Energy, Energy Company Development Patterns in the Postembargo Era, Vol. 1 and Vol. 2, DOE/EIA-0349 (Washington, D.C., October 1982).

[4]For purposes of this report, the United States typically includes the 50 states, the District of Columbia, Puerto Rico, and the U.S. Virgin Islands. However, there are some exceptions, which cover only the 50 states and the District of Columbia.

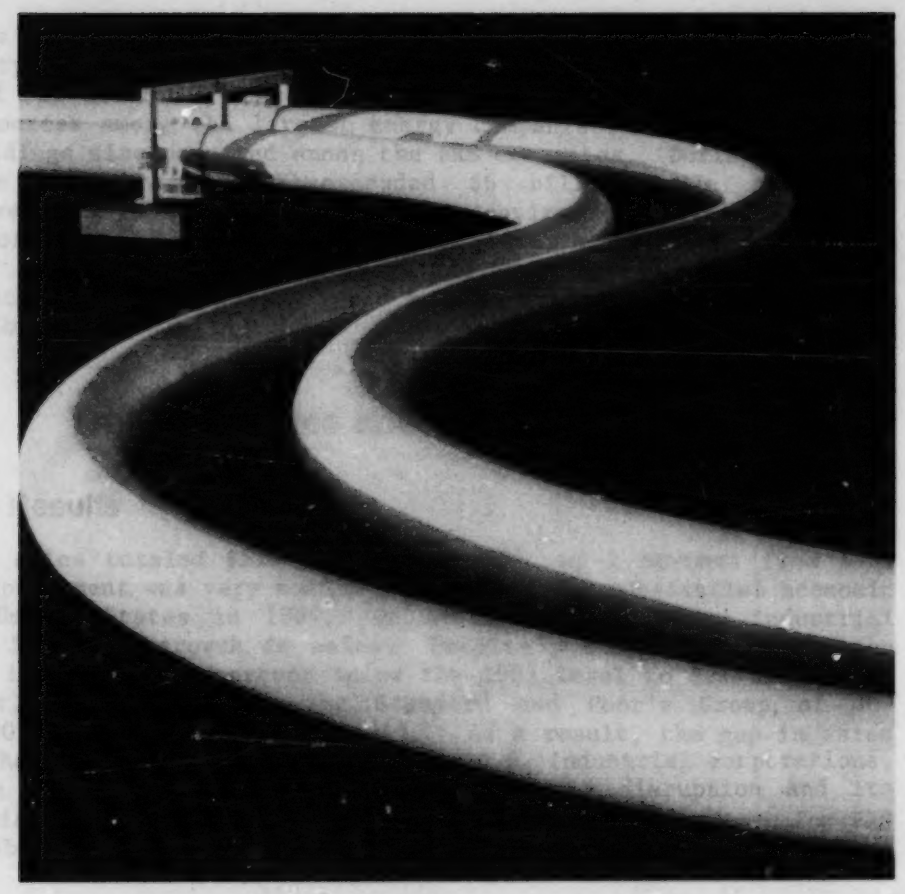
[5]Fortune (April 29, 1985, and June 10, 1985).

[6]Natural gas and oil are collectively referred to as petroleum, since many of their financial aspects cannot be separated. However, data on sales, production, resource development and reserves are collected separately for oil and gas and are discussed in subsequent sections.

[7]The data for total U.S. production of crude oil and natural gas liquids and natural gas (dry) utilized in this report are taken from Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216(84) (Washington, D.C., September 1985). This source is utilized in order to preserve consistency between production reported in the context of oil and gas reserves and reserve additions and production reported elsewhere in this report. However, the official Energy Information Administration U.S. totals for crude oil and natural gas plant production are 3,862.8 million barrels in 1984 and 3,759.1 million barrels in 1983 (see Energy Information Administration, Petroleum Supply Annual, 1984, Vol.1, DOE/EIA-0340(84)/1 (Washington, D.C., June 1985), p. 16). For dry natural gas production, the official Energy Information Administration U.S. totals are 17,231 billion cubic feet in 1984 and 16,033 billion cubic feet in 1983 (see Energy Information Administration, Natural Gas Monthly, August 1985, DOE/EIA-0130(85/08) (Washington, D.C., October 1985), p. 7).

Chapter 2

Key Financial Trends



Natural Gas Pipeline

Chapter 2

Key Financial Trends

2. Key Financial Trends

In 1984, strong economic growth prevailed in the United States. The Gross National Product rose 7 percent in real terms. All sectors of the economy benefited, but in varying degrees. Among those benefiting the least was the petroleum industry. Although petroleum product demand rose in 1984, reversing a five-year decline, the increase was only 3 percent.[1] In the context of this modest recovery in demand, U.S. crude oil prices tended to be weak, falling an average of 1 percent over the year. Uncertainties continued to pervade international oil markets. The Organization of Petroleum Exporting Countries' (OPEC) output continued to fall and tension within the cartel grew throughout the year, culminating with a conference in November 1984. The objectives of this conference were to lower and realign member output quotas and install a new monitoring program to promote cartel solidarity. Oil markets outside of the United States were further unsettled by the rapid rise of the U.S. dollar, relative to other currencies, which caused crude oil prices in many countries to rise despite reductions in dollar-denominated prices.

In aggregate these forces caused the financial performance of most major energy companies to lag that of other large enterprises. As a consequence, the value of some FRS companies' common shares tended to decline. In this context, challenges to existing management strategies were mounted against several large FRS companies. These challenges resulted in a significant realignment of ownership structure within the FRS group.

Three large mergers among FRS companies--Chevron's acquisition of Gulf, Texaco's acquisition of Getty Oil, and Mobil's acquisition of Superior Oil--involved an aggregate outlay of $29 billion. These mergers served to increase the ownership of oil and gas resources among the largest energy companies. Other significant shifts in asset holdings also occurred among the FRS companies. During 1984, the value of spinoffs and divestitures exceeded $6 billion. In part, the divestitures involved the sale of parts of newly acquired companies. In part, they reflected efforts by FRS companies to reduce commitments in non-petroleum lines of business. Through investment strategy and asset restructuring in 1984, the FRS companies accelerated the trend toward greater specialization in upstream oil and gas operations.

Trends in Sales and Income

Overall Corporate Results

The FRS companies' sales totaled $517 billion in 1984, up 1 percent from 1983 (Table 1). This improvement was very modest considering the substantial economic expansion in the United States in 1984. On average, other large industrial companies reported 5-percent growth in sales. Despite a rise in revenues, the FRS companies' net income fell 3 percent below the 1983 level to $21 billion in 1984. In contrast, net income for the Standard and Poor's Group of 400 industrials (S&P 400) rose 22 percent (Table 1).[2] As a result, the gap in rates of return between the FRS companies and other large U.S. industrial corporations, which arose in the context of the 1979 crude oil supply disruption and its aftermath, was eliminated in 1984 (Figure 2). The overall rate of return for FRS companies equaled about 12 percent on stockholders' equity in 1984, down from a

Table 1. A Comparison of Selected Financial Items for FRS Companies and the S&P 400, 1984 and Percent Change from 1983

Selected Financial Items	All FRS Companies		S&P 400	
	1984 (billion dollars)	Percent Change from 1983	1984 (billion dollars)	Percent Change from 1983
Income Statement				
Operating Revenues	517.4	1.3	1,936.5	5.4
Operating Expenses	-467.3	1.0	-1,762.5	5.2
Operating Income	50.1	3.9	174.0	6.9
Other Income[a]	-2.7	NM	-10.7	NM
Income Taxes	-26.1	2.6	70.1	7.5
Net Income	21.3	-2.8	93.2	22.3

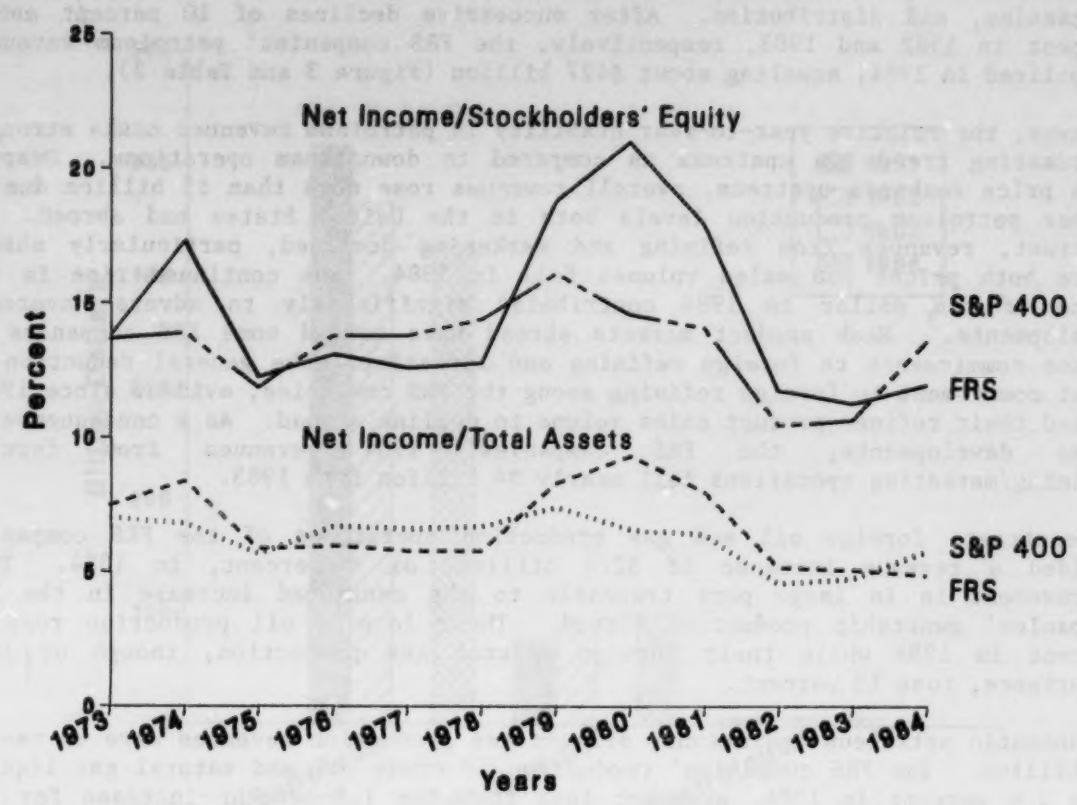
[a]"Other Income" includes other revenue and expense, extraordinary items, and accounting changes.
NM = Not meaningful.
Sources: •FRS companies: Form EIA-28. •S&P 400: Compustat Inc.

Table 2. Allocated Revenues, Income, and Investment for FRS Companies, 1984

Revenues, Income, and Investment	Total[a]	Petroleum	Nonpetroleum Energy	Chemicals	Other Nonenergy
	(billion dollars)				
Operating Revenues	534.2	426.7	7.6	51.0	49.0
Net Income	27.0	23.6	0.5	2.3	0.5
Net Investment in Place[b]	301.8	227.7	13.8	21.7	38.6
Additions to Investment in Place	77.3	66.8	2.6	3.3	4.6
Additions to Investment in Place Excluding Mergers	47.7	38.8	1.9	2.8	4.2
	(percent distribution)				
Operating Revenues	100.0	79.9	1.4	9.5	9.2
Net Income	100.0	87.5	1.8	8.7	2.0
Net Investment in Place[b]	100.0	75.4	4.6	7.2	12.8
Additions to Investment in Place	100.0	86.4	3.4	4.3	6.0
Additions to Investment in Place Excluding Mergers	100.0	81.4	4.0	5.8	8.8

[a]Excludes nontraceables and eliminations.
[b]Measured as net PP&E plus Investments and Advances.
Note: Sum of components may not equal total due to independent rounding. Percentages calculated from unrounded data.
Source: Form EIA-28.

Figure 2. Selected Performance Measures for FRS Companies and the S&P 400, 1973-1984



Sources: • FRS Companies - Form EIA-28. • S&P 400 - Compustat, Inc.

high of 21 percent in 1980. Their rate of return in 1984 was similar to those experienced in the mid-1970s.

Line-of-Business Results

Despite substantial sales and asset commitments in lines of business other than petroleum, 80 percent of all revenues were derived from petroleum production, processing, and distribution. After successive declines of 10 percent and 9 percent in 1982 and 1983, respectively, the FRS companies' petroleum revenues stabilized in 1984, equaling about $427 billion (Figure 3 and Table 2).

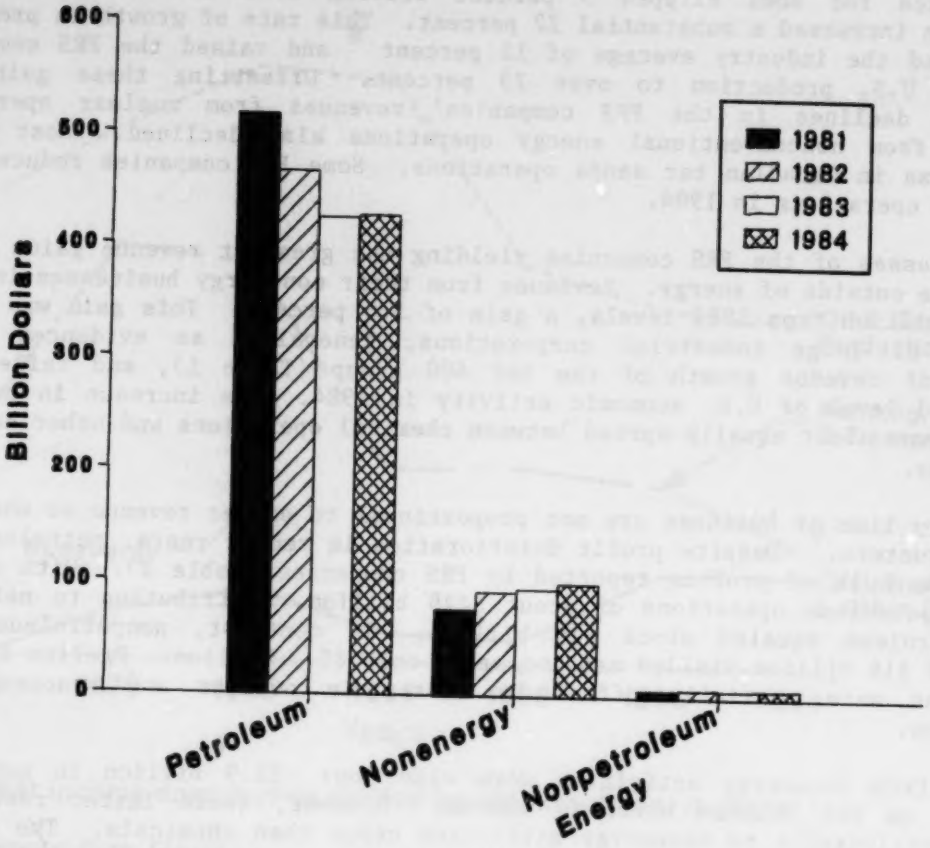
However, the relative year-to-year stability in petroleum revenues masks strongly contrasting trends in upstream as compared to downstream operations. Despite some price weakness upstream, overall revenues rose more than $3 billion due to higher petroleum production levels both in the United States and abroad. In contrast, revenues from refining and marketing declined, particularly abroad where both prices and sales volumes fell in 1984. The continued rise in the value of the dollar in 1984 contributed significantly to adverse overseas developments.[3] Weak product markets abroad have caused some FRS companies to reduce commitments to foreign refining and marketing. The general reduction in asset commitment to foreign refining among the FRS companies, evident since 1980, caused their refined product sales volume to decline abroad. As a consequence of these developments, the FRS companies' 1984 revenues from foreign refining/marketing operations fell nearly $4 billion from 1983.

By contrast, foreign oil and gas production operations of the FRS companies yielded a revenue increase of $2.4 billion, or 6 percent, in 1984. This improvement is in large part traceable to the continued increase in the FRS companies' ownership production abroad. Their foreign oil production rose 10 percent in 1984 while their foreign natural gas production, though of less importance, rose 12 percent.

In domestic petroleum operations, oil and gas production revenues were up nearly $3 billion. The FRS companies' production of crude oil and natural gas liquids rose 1.4 percent in 1984,[4] somewhat less than the 1.8-percent increase for the U.S. as a whole.[5] Natural gas production recovered from the imbalances of the 1982-1983 period, rising 8 percent for the FRS companies and 9 percent for the overall industry.[6] However, U.S. oil prices fell again in 1984, by 1 percent,[7] while natural gas prices at the wellhead were essentially flat on a year-to-year basis. On balance, the increases in oil and gas production outweighed the declines in price to produce a revenue increase from U.S. oil and gas production.

The FRS companies' revenues from U.S. refined product sales increased by $0.5 billion in 1984, or 0.3 percent, despite a 4-percent increase in their volume of refined product sales. Declines in most petroleum product prices offset most of the gain in sales volume. Performance in U.S. refining/marketing was adversely affected by the combination of the British coal workers' strike and increased refining capacity abroad in 1984. The strike, which began in March, 1984, and lasted for a year, led to an increase in demand for residual fuel oil in Great Britain to substitute for diminished coal availability. As residual fuel output rose, so did the output of all refined products. For other products, supplies increased at a more rapid pace than did demand with the result that downward price pressures were present during the second half of 1984. For the FRS

Figure 3. Operating Revenues by Line of Business for FRS Companies, 1981-1984



Source: Form EIA-28.

companies, the average sales price of refined products sold in the United States fell by $1.29 per barrel, a decline of nearly 4 percent, in 1984.

Revenues from other energy operations totaled $7.6 billion in 1984, $0.3 billion over 1983 revenues. The bulk of these revenues, $5.8 billion, and all of the revenue increase are attributable to the FRS companies' coal operations which were sustained at record levels in 1984. Although the FRS companies' average sales price for coal slipped 5 percent between 1983 and 1984, their coal production increased a substantial 22 percent. This rate of growth in production outstripped the industry average of 15 percent [8] and raised the FRS companies' share of U.S. production to over 25 percent. Offsetting these gains were continued declines in the FRS companies' revenues from nuclear operations. Revenues from nonconventional energy operations also declined. Most of the decline was in Canadian tar sands operations. Some FRS companies reduced their tar sands operations in 1984.

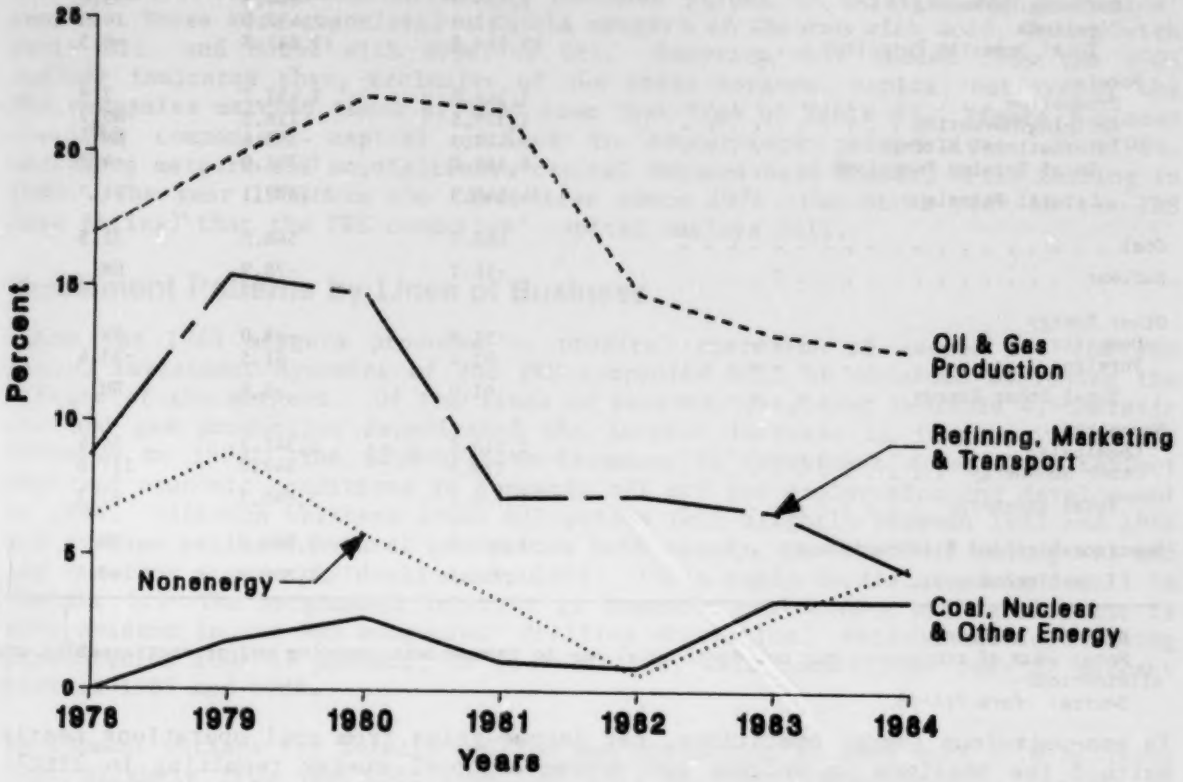
The businesses of the FRS companies yielding the greatest revenue gains in 1984 were those outside of energy. Revenues from their nonenergy businesses increased over $5 billion from 1983 levels, a gain of 5.5 percent. This gain was similar to that of large industrial corporations, generally, as evidenced by the 5.4-percent revenue growth of the S&P 400 group (Table 1), and reflects the heightened level of U.S. economic activity in 1984. The increase in nonenergy revenues was about equally spread between chemical operations and other nonenergy businesses.

Profits by line of business are not proportional to either revenue or underlying asset structure.[9] Despite profit deterioration in recent years, petroleum still yields the bulk of profits reported by FRS companies (Table 2). With an asset base in petroleum operations of about $228 billion, contribution to net income from petroleum equaled about $24 billion. In contrast, nonpetroleum energy assets of $14 billion yielded net income of only $0.5 billion. Profits from coal operations were partially offset by losses in nuclear and nonconventional activities.

Returns from nonenergy activities were also low: $2.9 billion in net income relative to $60 billion worth of assets. However, these latter results are solely attributable to nonenergy activities other than chemicals. The share of net income from chemical operations (9 percent) was in rough proportion to the assets allocated to these operations (7 percent), as was the case for petroleum operations as a whole. In contrast, net income yielded by nonenergy businesses other than chemicals as a proportion of total allocated net income, amounted to only 2 percent compared to an asset share of 13 percent.

Rates of return on investment by line of business are shown in Figure 4. The rate of return in worldwide oil and gas production declined in 1984, as it has since 1980. Although net income contributed by domestic oil and gas production rose 9 percent in 1984, and net income traceable to foreign oil and gas production was up 3 percent from the prior year (Table 3), growth in the asset base in oil and gas production outpaced income gains, resulting in a fall in the rate of return. The rate of return in worldwide petroleum refining, marketing, and transport operations fell sharply, reflecting the drop of over $2 billion in net income from worldwide refining/marketing operations.

Figure 4. Rates of Return by Line of Business for FRS Companies, 1978-1984[a]



[a]Net income contribution divided by net investment in place.

Source: Form EIA-28.

Table 3. Line-of-Business Contributions to Net Income for FRS Companies, 1983-1984

Line of Business	1983	1984	Percent Change from 1983
	(million dollars)		
Petroleum			
Domestic			
Production	12,217.6	13,256.4	8.5
Refining/Marketing	1,635.9	104.8	-93.6
Pipelines	2,013.9	2,497.0	24.0
Total Domestic Petroleum	15,888.9	15,841.3	-0.3
Foreign			
Production	7,246.0	7,457.2	2.9
Refining/Marketing	1,319.5	716.3	-45.7
International Marine	-472.3	-393.6	NM
Total Foreign Petroleum	8,160.0	7,791.9	-4.5
Total Petroleum	24,048.3	23,632.1	-1.7
Coal	468.0	568.8	21.5
Nuclear	-16.2	-78.9	NM
Other Energy			
Domestic	-51.5	-68.0	NM
Foreign	92.4	61.5	-33.4
Total Other Energy	41.0	-6.6	NM
Nonenergy			
Chemicals	1,516.6	2,341.2	54.4
Other Nonenergy	259.5	549.0	111.6
Total Nonenergy	1,776.1	2,890.2	62.7
Nontraceables and Eliminations	-4,402.9	-5,696.8	NM
Net Income	21,914.4	21,308.9	-2.8

NM = Not meaningful.
Note: Sum of components may not equal total due to independent rounding and/or nontraceables and eliminations.
Source: Form EIA-28.

In non-petroleum energy operations, net income gains from coal operations nearly matched the declines in nuclear and nonconventional energy resulting in little change in the rate of return to these operations. For the second year in a row, the FRS companies' nonenergy businesses registered a net income increase in excess of $1 billion. As a consequence, the rate of return to nonenergy rose to a level unmatched since 1979 (Figure 4). However, it is still only one-half the level realized from oil and gas production activities.

Figure 4 clearly indicates that the dispersion in rates of return across the FRS companies' lines of business has been diminishing in recent years. The substantial changes in energy markets since 1981 and the changes in the FRS companies' investment strategies have largely caused this result. Oil and gas production is still the most profitable line of business, accounting for over half of the FRS companies' investment base, and to an increasing extent the FRS companies' profit performance rests on performance realized from these operations.

Investment Trends

Overall Investment

Capital outlays[10] of the FRS companies totaled $78.2 billion in 1984. Compared to 1983 this represented a $30.2 billion increase. However, $29.9 billion of the 1984 outlays were accounted for by purchase values of existing FRS companies' assets. These were associated with the mergers of Chevron with Gulf, Texaco with Getty Oil, and Mobil with Superior Oil. Removing this amount from the 1984 outlays indicates that, exclusive of the three mergers, capital outlays of the FRS companies matched those of 1983 (see last line of Table 4). Figure 5 places the FRS companies' capital outlays in longer-term perspective. In 1984, excluding mergers and acquisitions, capital outlays held steady, after falling in 1983. The year 1983 was the first time since 1974 (the first year in the FRS data series) that the FRS companies' capital outlays fell.

Investment Patterns by Lines of Business

Since the 1984 mergers produced no physical accretion of assets for the FRS group, investment dynamics of the FRS companies will be examined excluding the effects of the mergers. Of the lines of business displayed in Table 4, domestic oil and gas production experienced the largest increase in investment outlays relative to 1983. The $2.8-billion increase in investment appears to reflect improved economic conditions in domestic oil and gas exploration and development in 1984. Although wellhead crude oil prices fell slightly between 1983 and 1984 and average wellhead natural gas prices held steady, the costs of adding oil and gas reserves apparently declined in 1984. (This topic is discussed in detail in Chapter 5.) The heightened interest in domestic exploration and development is more evident in the FRS companies' drilling statistics. While domestic drilling expenditures rose 17 percent, or $1.7 billion, well completions rose 27 percent between 1983 and 1984.

Investment outlays for foreign oil and gas production in 1984 were $7.0 billion, down slightly from the 1983 level of $7.2 billion. Nevertheless, because of lower drilling costs, foreign well completions rose 24 percent, similar to the 27-percent rise in U.S. completions.

In 1984, investment in domestic petroleum refining/marketing operations by the FRS companies declined for the second consecutive year. This decline reflects a general winding down of refinery upgrading projects that were undertaken in the late 1970s and early 1980s. These projects were directed toward increasing the relative yields of higher-octane products and enabling refineries to process a wider variety of crude oil qualities. Between 1977 and 1982, the FRS companies' annual investment outlays for domestic refineries rose from $1.0 billion to $5.0 billion even though total crude distillation capacity was being reduced. Since 1982, investment outlays for domestic refining have fallen to $3.7 billion in 1983 and $2.7 billion in 1984 as upgrading projects reach or near completion (Table 4).

Table 4. Additions to Investments in Place[a] for FRS Companies, 1983-1984

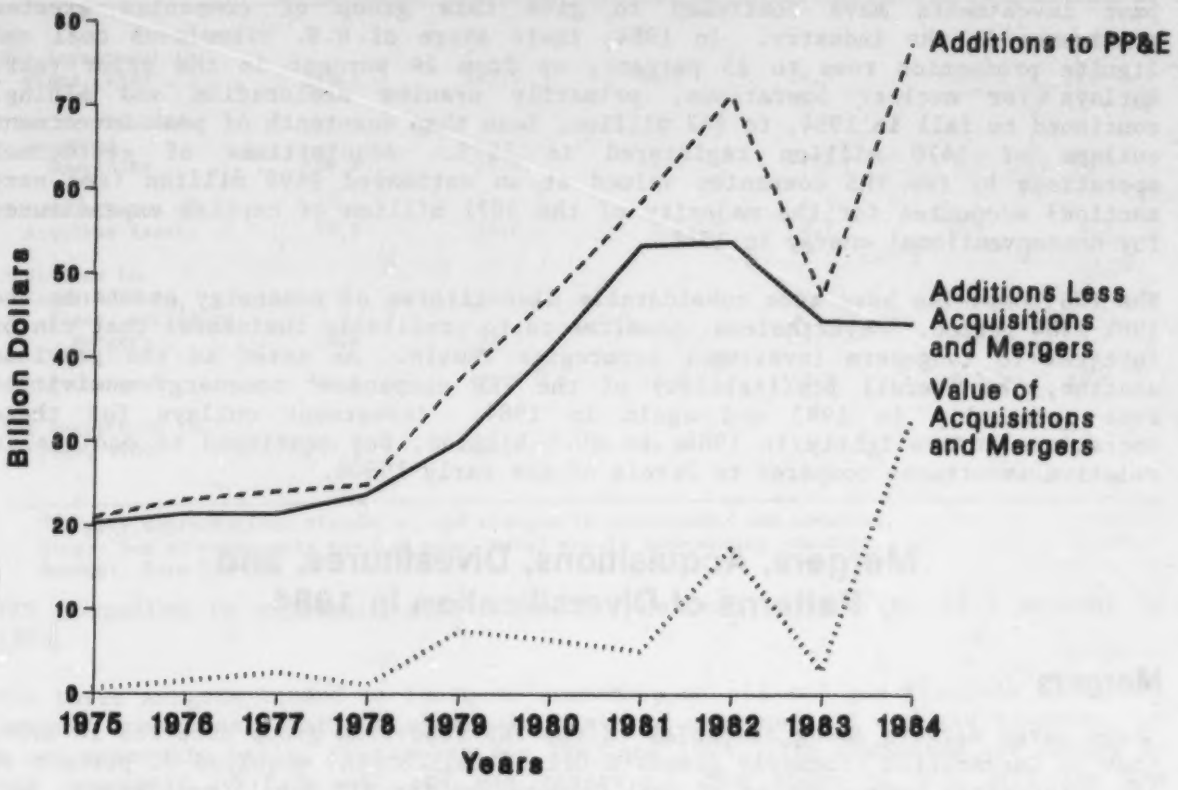
Line of Business	1983	1984	Adjusted[b] 1984	Percent Change From 1983	Adjusted[b] Percent Change From 1983
	(billion dollars)				
Domestic Petroleum					
Production	21.7	42.1	24.5	93.5	13.1
Refining/Marketing					
Refining	3.7	3.7	2.7	-0.5	-26.0
Marketing	1.2	2.8	1.8	134.1	46.3
Transport	0.4	0.3	0.3	-31.4	-33.0
Total Refining/Marketing	5.3	6.8	4.8	27.5	-10.2
Pipelines	2.1	0.9	0.6	-58.8	-73.1
Total Domestic Petroleum	29.1	49.7	29.9	70.5	2.6
Foreign Petroleum					
Production	7.2	14.0	7.0	93.1	-2.9
Refining/Marketing	1.8	2.8	1.9	57.6	4.0
International Marine	0.1	0.2	0.1	366.9	41.2
Total Foreign Petroleum	9.1	17.1	8.9	87.7	-1.3
Total Petroleum	38.2	66.8	38.8	74.6	1.7
Coal	1.1	1.6	1.0	45.8	-11.3
Nuclear	0.1	0.1	0.0[c]	86.7	-31.2
Other Energy					
Domestic	0.5	0.7	0.7	35.9	35.8
Foreign	0.2	0.2	0.2	-14.7	-14.7
Total Other Energy	0.7	0.9	0.9	21.5	21.5
Nonenergy					
Chemicals	2.8	3.3	2.8	15.8	-2.4
Other Nonenergy	4.0	4.6	4.2	14.3	4.3
Total Nonenergy	6.9	7.9	7.0	14.9	1.5
Nontraceables and Eliminations	1.0	0.9	0.7	NM	NM
Total Additions to Investment in Place	48.0	78.2	48.4	62.9	0.8

[a]Measured as additions to PP&E plus Investments and Advances.
[b]Adjusted to exclude approximately $29.9 billion in purchase value of existing assets associated with the mergers of Chevron with Gulf, Texaco with Getty Oil, and Mobil with Superior.
[c]Less than $50 million.
NM = Not meaningful.
Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.
Source: Form EIA-28.

In contrast, domestic petroleum marketing investments rose in 1984. A number of the FRS companies reported efforts to restructure and modernize retail gasoline distribution networks. In addition, some companies reported acquisitions of marketing outlets. As a result, investment outlays for domestic marketing rose from $1.2 billion in 1983 to $1.8 billion in 1984.

In 1983, the FRS companies' investment in pipelines rose sharply, to $2.1 billion, largely because of Burlington Northern's $1.6-billion acquisition of the

Figure 5. Additions to PP&E and Value of Acquisitions and Mergers for FRS Companies, 1975-1984



Sources: Form EIA-28 and company filings of Securities and Exchange Commission Form 10K.

El Paso Company. In 1984, pipeline investment fell to $0.6 billion, a level similar to that of 1983, excluding the El Paso acquisition.

The combined investment outlays for the coal, nuclear, and other energy lines of business were $1.9 billion in 1984. Although the FRS companies' investment in coal operations fell slightly in 1984, from $1.1 billion to $1.0 billion, their past investments have continued to give this group of companies greater prominence in the industry. In 1984, their share of U.S. bituminous coal and lignite production rose to 25 percent, up from 24 percent in the prior year. Outlays for nuclear operations, primarily uranium exploration and mining, continued to fall in 1984, to $42 million, less than one-tenth of peak investment outlays of $470 million registered in 1979. Acquisitions of geothermal operations by two FRS companies valued at an estimated $498 million (see next section) accounted for the majority of the $871 million of capital expenditures for nonconventional energy in 1984.

The FRS companies have made considerable divestitures of nonenergy assets in the 1981-1984 period. Nevertheless, commitments to profitable businesses that can be integral to long-term investment strategies remain. As noted in the previous section, the overall profitability of the FRS companies' nonenergy activities rose noticeably in 1983 and again in 1984. Investment outlays for these operations rose slightly in 1984, by $0.1 billion, but continued to decline in relative importance compared to levels of the early 1980s.

Mergers, Acquisitions, Divestitures, and Patterns of Diversification in 1984

Mergers

Three large mergers among companies in the FRS reporting group occurred in 1984. Chevron Corporation (formerly Standard Oil of California) acquired 82 percent of the outstanding common shares of Gulf Corporation for $13.3 billion; Texaco, Inc. acquired the common shares of Getty Oil Company for $10.2 billion; and Mobil Corporation acquired the common shares of The Superior Oil Company for $5.7 billion. All of these acquisitions were accounted for as purchases and the net assets acquired were allocated as additions to PP&E, based on estimated fair market values, for FRS reporting purposes.[11]

The effect of these mergers on the change in FRS companies' net investment in place between 1983 and 1984 was considerable. As seen in Table 5, the excess of the purchase value over book value of assets acquired in the three mergers totaled $5.0 billion, or 39 percent of the total change in net investment in place between 1983 and 1984. The difference between the purchase and book value of net PP&E in oil and gas was $7.8 billion while the balance of the difference was a negative $2.8 billion.

These mergers led to a considerable increase in long-term debt for the acquiring companies. For the FRS companies involved in the mergers (including the acquired companies), the net change in long-term debt between 1983 and 1984 totaled $22 billion while for other FRS companies the comparable change was a negative $1 billion. As a consequence of the mergers, the reported debt-equity ratio of the

Table 5. Sources of Change in Net Investment in Place for FRS Companies, 1984
(Billion Dollars)

Source of Change	Consolidated	Petroleum		Non-Petroleum Energy	Nonenergy	Non-Traceable
		Oil and Gas Production	Refining, Marketing and Transport			
Net Investment in Place, 1983	296.3	145.5	66.8	14.5	62.2	7.4
1983 Net PP&E of Acquired Companies	-24.9	-16.8	-4.4	-1.4	-1.7	-0.5
Purchase Value of Acquired Assets	29.9	24.6	3.4	0.7	0.9	0.3
Additions to Investment in Place, excluding Mergers	48.4	31.5	7.3	1.9	7.0	0.7
Other Changes[a]	-40.6	-21.9	-8.3	-1.9	-8.1	-0.6
Net Investment in Place, 1984	309.1	162.9	64.8	13.8	60.3	7.3

[a]Largely depreciation, disposals, and changes in investments and advances.
Note: Sum of components may not equal total due to independent rounding.
Source: Form EIA-28.

FRS companies in aggregate rose from 34.8 percent in 1983 to 49.5 percent in 1984.

The three mergers tended to increase ownership of oil and gas reserves among the largest companies. Table 6 shows the share of combined oil and gas reserves, on a net ownership basis, by company for 1983 and 1984. The companies are ranked by net ownership of U.S. oil and gas reserves. The share of U.S. oil and gas reserves owned by the top four companies increased by less than a percentage point between 1983 and 1984, from 25.8 percent to 26.7 percent, while the share of the top eight companies increased from 38.9 percent to 44.4 percent. Of this increase, 4.5 percentage points were accounted for by Chevron, Mobil, and Texaco, and 1 percentage point was attributable to growth in U.S. reserve ownership of other companies in the top eight. Most of the growth in the share of the top eight companies was the result of a shift in ownership among FRS companies, rather than an expansion in ownership of the FRS group as a whole. While the share of the top eight companies increased by over 5 percentage points, the overall share of the FRS companies increased by less than 1 percentage point, from 56.4 percent to 57.1 percent.

Table 6. U.S. Oil[a] and Natural Gas[b] Reserve Shares for FRS Companies (Net Ownership Basis), 1983 and 1984
(Percent)

1983 Company	Share	1984 Company	Share
Exxon	8.3	Exxon	8.3
Atlantic Richfield	7.1	Atlantic Richfield	7.4
Standard Oil (Ohio)	5.5	Standard Oil (Ohio)	5.8
Shell Oil	4.9	Chevron	5.1
Total Top Four	25.8	Total Top Four	26.7
Standard Oil (Indiana)	4.7	Shell Oil	5.1
Chevron	2.9	Standard Oil (Indiana)	4.9
Mobil	2.8	Texaco	4.3
Texaco	2.7	Mobil	3.5
Total Five through Eight	13.1	Total Five through Eight	17.7
Getty Oil	2.3	Unocal	2.0
Gulf Oil	2.1	Phillips Petroleum	1.9
Unocal	2.0	Sun	1.7
Sun	1.7	U.S. Steel	1.2
Phillips Petroleum	1.6	Tenneco	1.2
U.S. Steel	1.2	Du Pont	1.1
Tenneco	1.2	Occidental Petroleum	1.0
Du Pont	1.1	Union Pacific	0.7
Total Nine through Sixteen	13.1	Total Nine through Sixteen	10.8
Occidental Petroleum	0.9	Burlington Northern	0.7
Superior Oil	0.7	Amerada Hess	0.5
Union Pacific	0.7	Coastal	0.3
Burlington Northern	0.7	Kerr-McGee	0.2
Amerada Hess	0.6	American Petrofina	0.1
Coastal	0.3	Ashland Oil	0.1
Kerr-McGee	0.2	Total Other FRS	1.9
American Petrofina	0.1		
Ashland Oil	0.1		
Total Other FRS	4.4		

[a]Crude oil and natural gas liquids.
[b]Dry natural gas converted at 1 Mcf=.1772 barrel of crude oil.
[c]Sum of Chevron and Gulf Oil for 1984.
Note: Sum of components may not equal total due to independent rounding.
Sources: •Company oil and gas reserves from filings of Securities and Exchange Commission Form 10K. •U.S. total oil and dry natural gas reserves from Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216(84)(Washington, D.C., September 1985).

Other Acquisitions

Acquisitions by FRS companies in 1984, other than the three mergers, were valued at $3.6 billion (Table 7). Of this amount, $2.5 billion involved oil and gas production assets. Phillips paid $1.6 billion to acquire Aminoil, the oil and gas subsidiary of R. J. Reynolds Industries. Husky Oil, Ltd., a Canadian firm, as part of its effort to move out of U.S. oil and gas operations, sold its U.S. operations (mainly oil and gas properties) to U.S. Steel for $488 million. In a series of three acquisitions, Sun acquired oil and gas properties for $451 million.

Table 7. Estimated Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 1984

Affected Company	Acquiring Company	Type of Transaction	Estimated Value
			(million dollars)
Transactions within the FRS Group			
Gulf Oil Corporation	Chevron	Merger	13,300
Getty Oil Company	Texaco	Merger	10,200
Superior Oil Company	Mobil	Merger	5,720
Chevron Corporation (European refining/marketing assets)	Texaco	Asset Acquisition	217
Acquisition of non-FRS Companies or Assets			
Oil and Gas Production			
Aminoil (subsidiary of R.J. Reynolds Industries)	Phillips	Equity Acquisition	1,600
Husky Oil Company	U.S. Steel	Equity Acquisition	488
Victory Oil Company (heavy oil properties)	Sun	Asset Acquisition	281
Petro-Lewis (gas properties)	Sun	Asset Acquisition	94
Exeter Oil Company	Sun	Equity Acquisition	76
Other Energy			
Geysers Geothermal Company (subsidiary of R. J. Reynolds Industries)	Phillips	Equity Acquisition	213
The Geysers (additional 25 percent interest)	Unocal	Equity Acquisition	285
Nonenergy and Other			
Ecko Production, Car-X Service Systems, Creole Gas Pipeline Corporation	Tenneco	Equity Acquisitions	249
Daniel, Mann, Johnson, and Mendenhal; Scientific Gas Products Company; Goodyear (adhesive technologies division)	Ashland	Equity and Asset Acquisitions	64

Source: Securities and Exchange Commission Form 10K and companies' annual reports to shareholders.

In the nonconventional energy area, Phillips and Unocal increased their involvement in geothermal activities. The total value of the two acquisitions was an estimated $498 million, and accounted for the bulk of the $871 million of total FRS companies' capital expenditures for nonconventional energy of all types.

The FRS companies have, in recent years, divested themselves of a considerable amount of assets in nonenergy businesses, a trend which continued in 1984. Nevertheless, potentially profitable enterprises continue to be pursued in this area. Among the FRS companies in 1984, an estimated $313 million was expended for nonenergy businesses by Ashland and Tenneco (Table 7). However, these acquisitions represented only 4 percent of the FRS companies' $7.0 billion in capital expenditures (exclusive of merger purchase values) for nonenergy businesses in 1984.

Divestitures

The level of divestiture activity of the FRS companies in 1984 was maintained at the heightened levels that have been evident since 1981. Table 8 shows that the book value of disposals of PP&E was $6.0 billion in 1984 and $5.9 billion in 1983. The pace of divestiture activity in domestic downstream petroleum operations (refining, marketing, and transport) fell from $1.5 billion to $0.8 billion of disposals, but this falloff was nearly matched by an increase from $0.8 billion to $1.4 billion of disposals in foreign downstream petroleum operations.

Table 8. Book Value of Disposals of PP&E for FRS Companies, 1978-1984
(Billion Dollars)

Line of Business	1978	1979	1980	1981	1982	1983	1984
Petroleum							
Domestic	0.6	0.9	0.8	1.6	2.1	2.5	2.0
Foreign	0.6	0.6	0.5	2.0	1.4	1.4	1.7
Other	0.1	0.6	0.7	1.4	1.7	2.0	2.4
Total Disposals	1.4	2.1	2.0	5.0	5.3	5.9	6.0

Note: Sum of components may not equal total due to independent rounding.
Source: Form EIA-28.

The increased level of divestitures between 1981 and 1984 is traceable to several developments. First, companies have sold, or otherwise disposed of, operations which did not appear to fit with their long-term profit improvement strategies. Many FRS companies have disposed of nonenergy operations which yielded disappointing results. Second, energy conservation and shifts toward less energy-intensive products, largely induced by the episodes of crude oil price escalation in the 1973-1980 period, have lowered profit prospects for a significant number of refining and marketing facilities (see Chapter 4 and 6). Recent weakness in crude oil prices has also adversely affected nonconventional energy projects. Third, the mergers of 1982 (Du Pont-Conoco, U.S. Steel-Marathon Oil, and Occidental Petroleum-Cities Service) and 1984 (Chevron-Gulf, Texaco-Getty Oil, and Mobil-Superior Oil) resulted in the incurrence of large amounts of debt, which the acquiring companies have sought to reduce through

asset sales. Also, in some mergers, the Federal Trade Commission (FTC) has required sale of certain assets in order for the companies involved to gain FTC approval of the transaction. An additional factor stimulating divestitures in the 1981-1983 period was Canadian energy policy which required reduced foreign ownership of Canadian energy assets.

Table 9 lists the major divestitures of the FRS companies in 1984. The three companies involved in mergers in 1982 (Du Pont, Occidental Petroleum, and U.S. Steel) continued to sell assets and reduce their outstanding debt. Similarly, Texaco sold certain operations acquired in its merger with Getty Oil. Atlantic Richfield continued to divest itself of primary metals operations. In a transaction valued in excess of $200 million, Chevron sold refining and marketing operations in Europe to Texaco.

Table 9. Major Asset Disposals of FRS Companies, 1984

Company	Company or Property Disposed
Ashland	Australian and Malaysian carbon black interests.
Atlantic Richfield	ARCO Metals Company Division, an aluminum metal producing division. Laporte, Texas, chemical plant
Chevron	Northwestern European refining and marketing operations.
Du Pont	Conoco Chemicals businesses.
Kerr-McGee	Shutdown of Quivira, New Mexico, uranium mining and potash facilities.
Mobil	Mobil Chemical Company, Chemical Products Division, Coating Branch.
Occidental Petroleum . . .	Termination of Pension Plan. Occidental Geothermal, Inc. Claymore field in the North Sea. Australia Occidental Pty. Ltd. Reduced ownership in Canadian Occidental Petroleum, Ltd.
Standard Oil (Indiana) . .	80 percent interest in Amoco Australia, Limited. Engineered plastic business. Cultured yeast food business. Various marginal U.S. producing properties.
Texaco	Certain businesses acquired in merger with Getty Oil including: Employers Reinsurance Company; Interest in subsidiary of Mitsubishi Oil Company; Entertainment and Sports Programming Network; Chemplex Company; and Skelgas, Inc.
Union Pacific	Enid, Oklahoma, refinery and related properties.
U.S. Steel	Lynch, Dilworth and Robena Coal properties. Certain oil and gas properties. Alside Division, Electrical Cable and tire cord operations. Most of the assets of Ohio Barge Lines, Inc. Mon-Valley Transportation Company.

Source: Securities and Exchange Commission Form 10K and companies' annual reports to shareholders.

Diversification Patterns

The net effect of the FRS companies' investment strategies, mergers, and divestitures in 1984 accentuated some long-term trends and reversed other trends with respect to diversification. Table 10 displays the composition of net PP&E across lines of business for the period 1976-1984. The share of net PP&E

allocated to oil and gas production rose for the ninth consecutive year, to 55 percent in 1984. Over the same span, the share of assets deployed in downstream petroleum fell steadily, reaching 20 percent in 1984, as compared to 42 percent in 1976. Figure 6 shows that the share of net PP&E allocated to petroleum operations overall increased from 73 percent in 1983 to 75 percent in 1984, a reversal in the trend of slow decline evident since 1974. Table 10 and Figure 6 also indicate that nonenergy businesses accounted for a lesser share of assets in 1984 than in 1983 (18 percent versus 20 percent). After rising from 8 percent in 1974 to a peak of 12 percent in 1983 the share of FRS companies' net PP&E allocated to nonenergy businesses other than chemicals fell to 11 percent in 1984. For chemical operations, the share fell from a peak of 8 percent in 1982 to 7 percent in 1984.

Table 10. Distribution of Net PP&E by Line of Business for FRS Companies, 1976-1984

Line of Business	1976	1977	1978	1979	1980	1981	1982	1983	1984
	(billion dollars)								
Net PP&E	111.1	125.9	138.1	159.3	188.9	224.9	265.5	278.4	292.4
	(percent)								
Distribution of Net PP&E									
Petroleum									
Oil & Gas Production	38.5	40.0	41.3	45.1	48.5	50.5	50.7	51.7	55.2
Refining/Marketing, Transport	41.5	38.1	35.6	31.7	28.5	25.7	22.4	21.7	20.2
Coal	1.8	2.1	2.3	2.3	2.4	3.0	3.2	3.2	3.1
Nuclear	0.4	0.5	0.6	0.7	0.7	0.6	0.5	0.4	0.2
Other Energy	0.9	1.0	1.6	1.3	1.4	1.3	1.4	1.3	1.3
Nonenergy									
Chemicals	7.1	8.3	8.8	8.4	8.1	7.5	8.4	7.5	6.9
Other Nonenergy	8.7	8.9	8.8	9.4	9.3	10.0	11.8	12.2	11.4
Nontraceables[a]	1.0	1.0	1.0	1.0	1.1	1.4	1.8	1.9	1.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

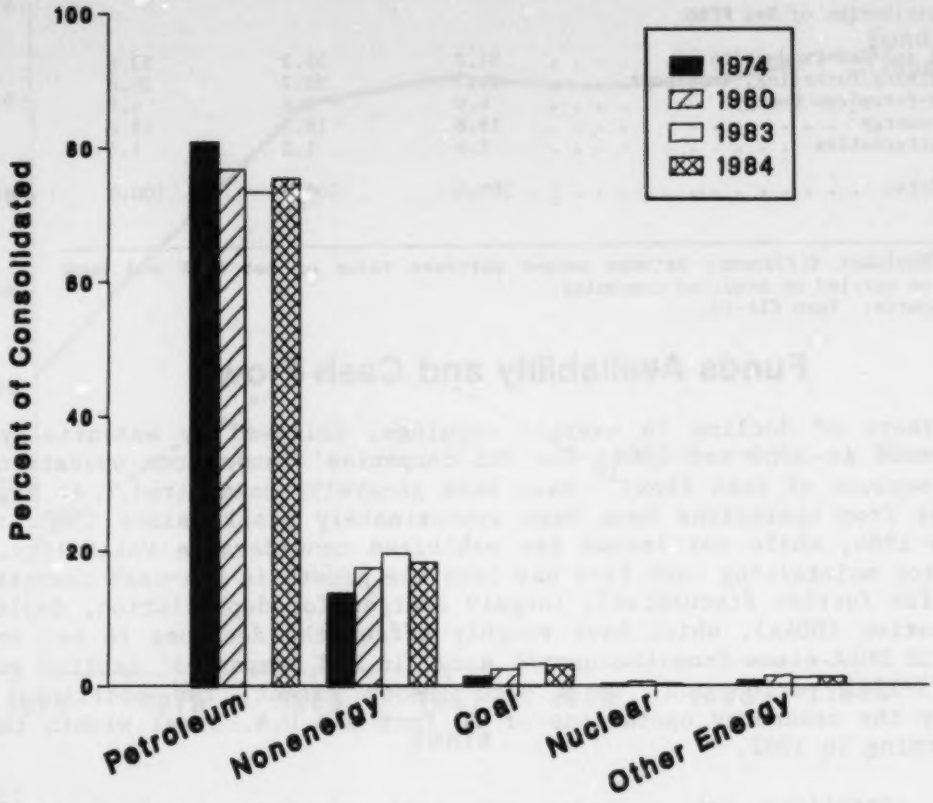
[a]Nontraceable revenues, costs, assets, and liabilities cannot be directly attributed to a line of business or cannot be assigned to a line of business by use of reasonable allocation methods based on operating-level realities.

Note: Sum of components may not equal total due to independent rounding.

Source: Form EIA-28.

The basic thrust of these trends was unaffected by the mergers of 1984 and the attendant revaluation of assets. Table 11 presents the distribution of net PP&E with the difference between merger purchase values and book values deleted as well as reporting the distribution presented in Table 10. Even after removing the upward revaluation of oil and gas production assets and the downward revaluation of other assets, it can be seen that the share of net PP&E accounted for by oil and gas production increased in 1984 while the shares for downstream petroleum and nonenergy decreased between 1983 and 1984.

Figure 6. Distribution of Net PP&E by Line of Business for FRS Companies, Selected Years



Source: Form EIA-28.

Table 11. Effect of Mergers on Distribution of Net PP&E by Line of Business for FRS Companies, 1983-1984
(Percent)

Line of Business	As Reported 1983	As Reported 1984	Adjusted[a] 1984
Distribution of Net PP&E			
Oil and Gas Production	51.7	55.2	53.6
Refining/Marketing, Transport	21.7	20.2	20.8
Non-Petroleum Energy	4.9	4.6	4.9
Nonenergy	19.8	18.3	18.8
Nontraceables	1.9	1.8	1.9
Total	100.0	100.0	100.0

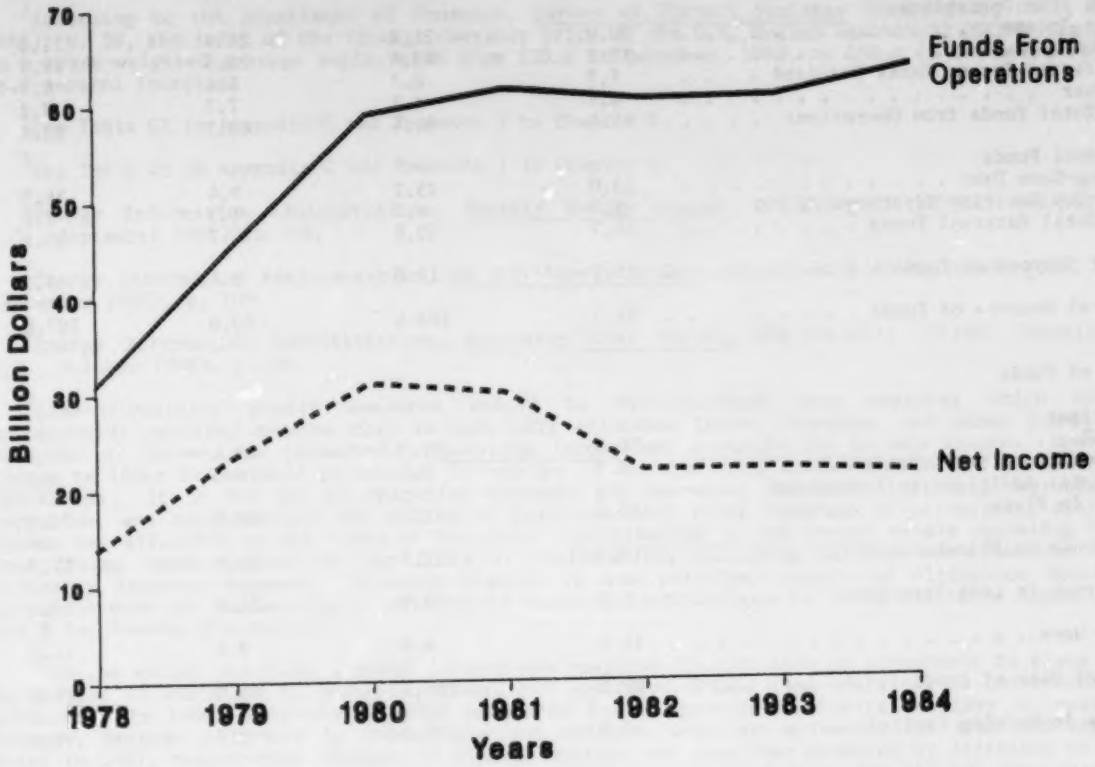
[a]Excludes difference between merger purchase value of net PP&E and book value carried by acquired companies.
Source: Form EIA-28.

Funds Availability and Cash Flow

Despite 2 years of decline in overall earnings, followed by essentially flat earnings growth in 1983 and 1984, the FRS companies' funds from operations (an often-used measure of cash flow)[12] have been generally unimpaired. As Figure 7 shows, funds from operations have been approximately stable since 1980, rising slightly in 1984, while net income has exhibited considerable volatility. The primary factor maintaining cash flow has been the growth in non-cash charges (see Appendix D for further discussion), largely charges for depreciation, depletion, and amortization (DD&A), which have roughly offset the declines in net income. The growth in DD&A stems from the upward surge in FRS companies' capital outlays in the 1979-1981 period and, to a much lesser extent, the additional DD&A generated by the nonenergy operations of Du Pont and U.S. Steel within the FRS group, beginning in 1982.

Funds from operations are a major component of Sources of Funds,[13] the composition of which is shown in Table 12. The second most important source of funds is issuance of long-term debt. Between 1981 and 1982, the total funding obtained by issuance of long-term debt nearly doubled, primarily to effect the three large mergers of 1982. Between 1982 and 1983, funds obtained through long-term debt dropped sharply. In 1984 issuance of long-term debt increased massively, from $9.4 billion in 1983 to $34.9 billion. This increase was associated with the three large mergers among the FRS companies in 1984. The three acquiring companies (Chevron, Mobil, and Texaco) together reported issuance of long-term debt of $25.6 billion in 1984. Exclusive of this amount, long-term debt issuance of FRS companies was nearly the same in 1984 as in 1983.

Figure 7. Total Funds From Operations and Net Income for FRS Companies, 1978-1984



Source: Form EIA-28.

Table 12. Components of Sources and Uses of Funds for FRS Companies, 1981-1984
(Billion Dollars)

Sources and Uses of Funds	1981	1982	1983	1984
Sources of Funds				
Funds from Operations				
Net Income	30.0	21.8	21.9	21.3
DD&A	19.2	23.9	26.5	29.2
Deferred Income Taxes Realized	7.7	6.7	4.6	4.9
Other	4.7	8.1	7.7	8.2
Total Funds from Operations	61.6	60.4	60.7	63.6
External Funds				
Long-Term Debt	13.0	25.2	9.4	34.9
Equity Security Offerings	1.7	6.7	1.3	1.0
Total External Funds	14.7	32.0	10.7	35.9
Other Sources of Funds	5.5	11.0	9.4	7.5
Total Sources of Funds	81.7	103.4	80.8	107.0
Uses of Funds				
Additions				
PP&E	58.7	71.3	47.4	77.6
Investments and Advances	1.9	1.1	0.5	0.6
Total Additions to Investment in Place	60.6	72.5	48.0	78.2
Dividends to Shareholders	10.7	11.4	11.8	11.9
Reduction in Long-Term Debt	5.9	13.7	11.8	12.1
Other Uses	11.4	8.8	8.4	14.5
Total Uses of Funds	88.6	106.4	80.0	116.8
Change in Working Capital	-6.8	-3.0	0.8	-9.8

Note: Sum of components may not equal total due to independent rounding.
Source: Form EIA-28.

Since 1982, funds used to reduce long-term debt have increased markedly. Part of the impetus for this increase was the decline in nominal interest rates that began in 1982. Rollovers of relatively high interest rate debt was accelerated in order to achieve lower interest charges. Also, a number of FRS companies announced strategies that would achieve lower debt-equity ratios. The most important factor, however, was the desire of companies involved in the large mergers of 1982 to reduce debt incurred to finance acquisitions. The three acquiring companies in the 1982 mergers, Du Pont, Occidental Petroleum, and U.S. Steel, together accounted for nearly $4 billion, or one third, of the FRS companies' reduction in long-term debt in both 1983 and 1984.

Footnotes to Chapter 2

[1]Energy Information Administration, Monthly Energy Review, DOE/EIA-0035 (85/06)(Washington, D.C., September 1985), p. 40.

[2]The S&P 400 is a well-recognized data base that includes 400 of the largest U.S. industrial companies. In 1984, 16 of the FRS companies were included in the S&P 400. Financial statistics for the S&P 400 were obtained by accessing Compustat, a service of Standard and Poor's, Inc.

[3]According to the Department of Commerce, Survey of Current Business (Washington, D.C., March 1985), p. 30, the index of the foreign currency price of the U.S. dollar against 22 OECD currencies, on a trade-weighted average basis, rose from 135.8 in December, 1983, to 158.3 in December, 1984, a 16.6-percent increase.

[4]See Table G1 in Appendix G and Footnote 7 in Chapter 1.

[5]See Table G1 in Appendix G and Footnote 7 in Chapter 1.

[6]Energy Information Administration, Monthly Energy Review, DOE/EIA-0035 (85/06) (Washington, D.C., September 1985), p. 95.

[7]Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(85/06)(Washington, D.C., September 1985), p. 105.

[8]Energy Information Administration, Quarterly Coal Report, DOE/EIA-0121 (85/2Q) (Washington, D.C., October 1985), p. 69.

[9]Line-of-business profit measures should be distinguished from measures which reflect company-wide results, because they reflect only allocable income, expense, and asset items. Two measures of income are presented: operating income and contribution to net income. Operating income by lines of business is similar in concept to the operating income measure for total company operations. It is the net of operating revenues and operating expenses (including depreciation, depletion, and amortization) for a line of business. All items involved in calculating operating income are allocated to the lines of business. Contribution to net income equals operating income less income taxes imputed to the lines of business but excluding certain non-allocable items, primarily interest expense. Interest expense is the principal source of difference between a corporate-wide net income figure and line-of-business contributions to net income (see Appendixes D and E for further discussion).

[10]To the extent possible, capital outlays are measured by additions to investment in place which is defined as additions to property, plant, and equipment (PP&E) plus additions to investments and advances. In 1984, additions to PP&E accounted for 99 percent of capital outlays so measured. However, because additions to investments and advances were not collected for some FRS segments prior to 1981, year-to-year changes in capital outlays are sometimes measured by additions to PP&E. Also, in comparisons with the S&P 400, this latter measure is used since the S&P 400 data base does not provide an item comparable to additions to investments and advances.

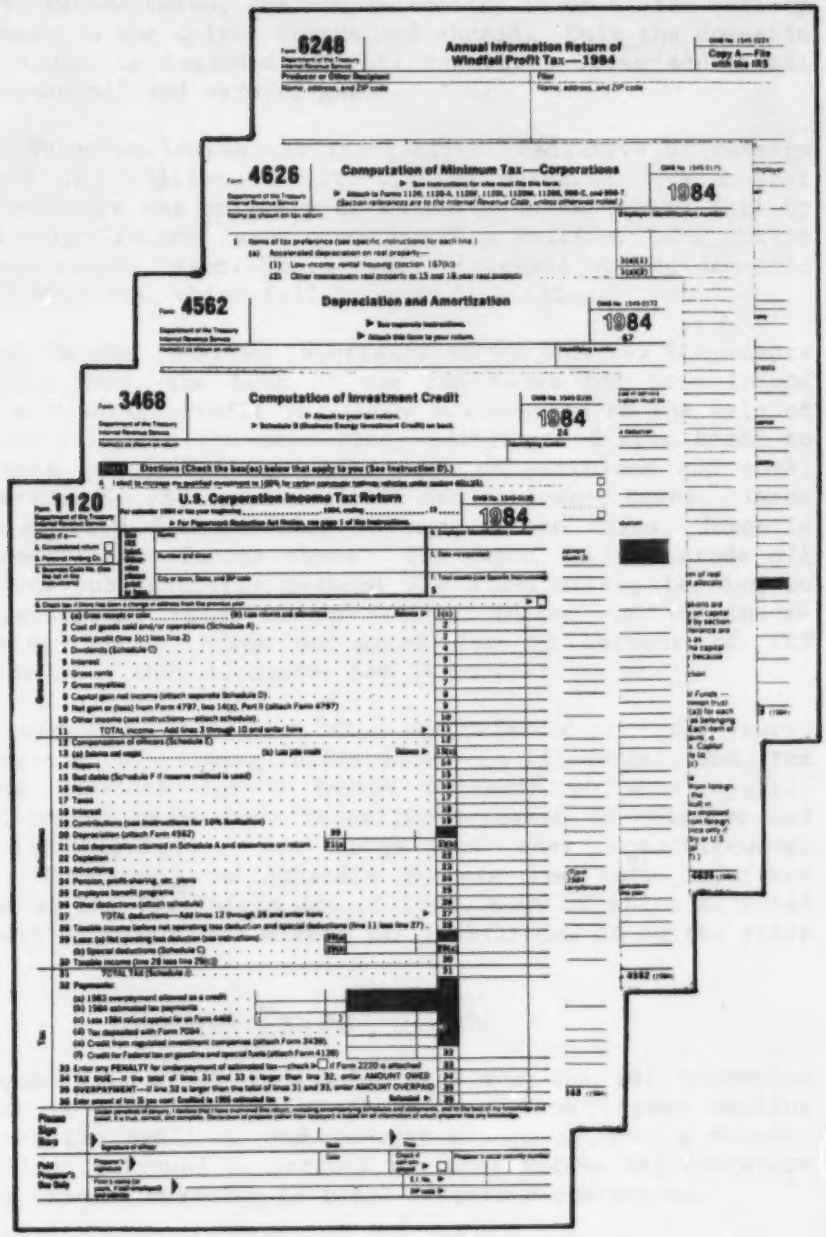
[11]It should be noted that for FRS reporting purposes, the year-end balances for companies acquired through merger are set equal to zero. This procedure prevents double counting of assets and liabilities, which were effectively absorbed by the acquiring companies and are reflected in their year-end balances, and double counting of year-end energy reserves of acquired companies, which are reflected as purchases of minerals in place by the acquiring companies. However, the acquired companies' production, income, and investment activity, prior to consolidation by the acquiring company, are reported in order to prevent undercounting.

[12]See Appendix D for a detailed discussion of the concept of funds from operations.

[13]The "Sources of Funds Schedule" gives an accounting of funds generated internally through a company's operations during the course of a year (termed funds from operations) and funds obtained through the issuance of long-term debt and equity securities (termed external funds). The "Uses of Funds" Schedule provides an accounting of the applications of funds which are held to benefit the equity position of the company or benefit the equity holders directly (i.e., dividends). The accounting framework is designed so that the difference between sources of funds and uses of funds equals the change in working capital (working capital is defined as the difference between current assets and current liabilities).

Chapter 3

Taxation



Federal Corporate Tax Forms

3. Taxation

Taxes occupy a major position in the financial operations of the FRS companies. Taxes paid by these companies are greater, relative to their pretax incomes, than are those for the average of all large U.S. corporations. This difference reflects the existence of high foreign tax rates, the greater share of petroleum company operations conducted abroad, and the levying of energy-specific taxes domestically.

FRS companies have extensive foreign petroleum operations. The effective foreign income tax rates for these and other consolidated foreign operations greatly exceed domestic rates. The effective rates for FRS companies' worldwide operations also exceed effective worldwide rates for the S&P 400 group of companies.[1] In addition to income taxes, FRS companies also incur a wide variety of other tax liabilities both in the United States and abroad. Only the domestic component of these other taxes is included in this report.[2] These additional taxes apply primarily to crude oil and natural gas.

In 1984, FRS companies incurred worldwide tax liabilities (exclusive of foreign non-income taxes) of about $42 billion, a $1.5-billion decrease from a year earlier (Figure 8). The decrease was entirely in domestic taxes, which fell by about $2 billion while foreign income taxes rose by $0.5 billion. The entire domestic decline was in non-income taxes. The largest component in the domestic decline was the Windfall Profit Tax, which fell by over $1 billion.

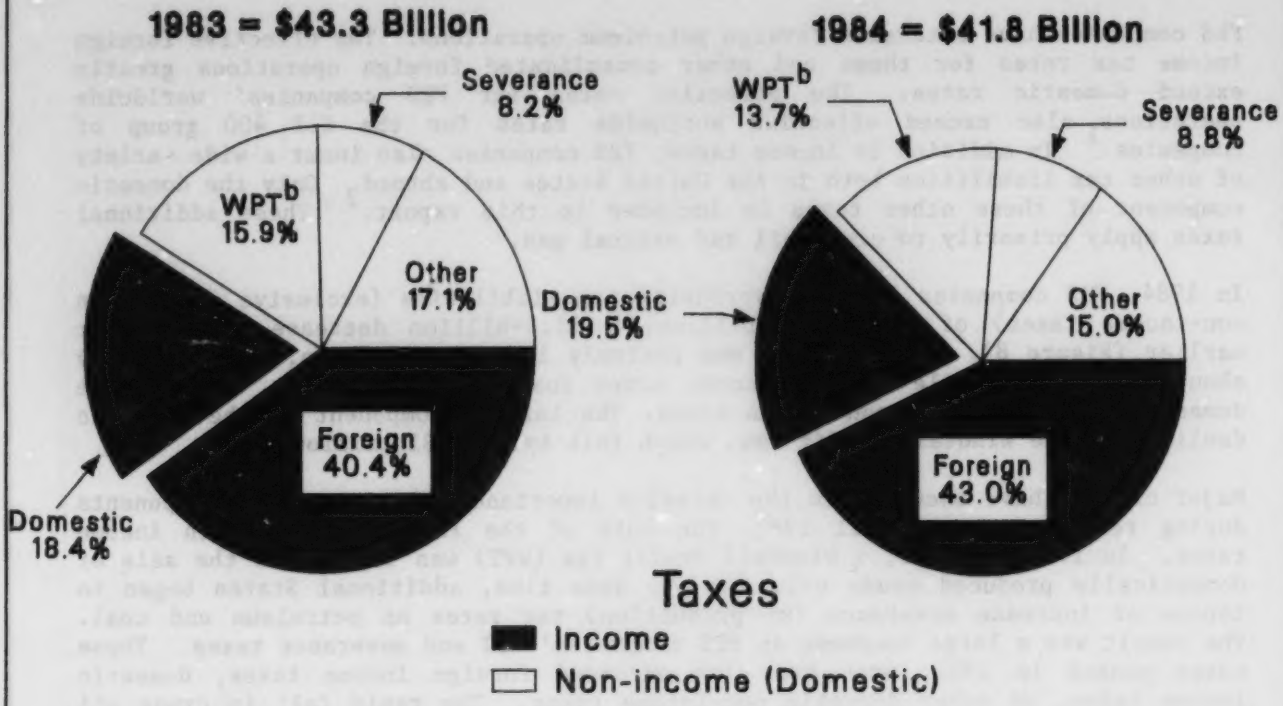
Major changes have occurred in the relative importance of various tax components during recent years. Until 1980, the bulk of the FRS taxes had been income taxes. In 1980, however, a Windfall Profit Tax (WPT) was imposed on the sale of domestically produced crude oil. At the same time, additional States began to impose or increase severance (or production) tax rates on petroleum and coal. The result was a large increase in FRS companies' WPT and severance taxes. These taxes peaked in 1981, when they far exceeded foreign income taxes, domestic income taxes, or other domestic non-income taxes. The rapid fall in crude oil prices since early 1981 has substantially reduced WPT liabilities, tending to re-establish the more traditional relationship between income and non-income taxes. In 1984, worldwide income taxes accounted for 63 percent of FRS companies' total taxes. In 1981, they accounted for 54 percent.

Not all income taxes are current liabilities. Many are deferred to later years. Deferred taxes arise because of timing differences in financial and tax reporting. Tax reporting provides for a faster writeoff of many capital expenditures. Although deferred taxes have recently decreased in relative and absolute importance, their magnitudes are large and they are discussed extensively below. Also discussed, in Appendix H, are the more important energy-specific provisions of the Tax Reform Act of 1984, some of which affected 1984 tax liabilities and all of which will affect tax liabilities in future years in some measure.

Income Taxes

Worldwide income tax expenses (current and deferred[3]) for the FRS companies amounted to $26.1 billion in 1984, up almost $1 billion from a year earlier (Table 13). The change was the smallest year-to-year change in over a decade. Upstream petroleum activities continued to account for most income and therefore for most of the income tax expense accruing to total corporate operations.

Figure 8. Worldwide Tax Liabilities of FRS Companies, 1983-1984[a]



[a] Excludes foreign taxes other than income taxes. Also excludes domestic consumer excise taxes collected by FRS companies for governments.

[b] WPT = Windfall Profit Tax.

Source: Form EIA-28.

Table 13. Income Tax Expense, Pre-Tax Income, and Tax Shares for FRS Companies, Selected Years, 1974-1984

Taxes and Pre-Tax Income	1974	1976	1978	1980	1981	1982	1983	1984
	(billions of dollars)							
Income Taxes								
U.S. Federal	2.7	4.9	5.9	12.3	11.6	7.6	7.3	7.4
U.S. State and Local	0.3	0.4	0.6	1.6	1.7	0.8	0.7	0.8
Foreign	14.6	8.3	9.7	22.4	16.8	15.1	17.5	18.0
Total	17.6	13.6	16.1	36.3	30.1	23.5	25.5	26.1
Worldwide Pre-Tax Income	31.3	25.9	30.2	66.9	59.6	45.2	47.4	47.6
	(percent)							
Distribution of Total Income Taxes								
U.S. Federal	15.3	36.0	36.6	33.9	38.5	32.3	28.5	28.3
U.S. State and Local	1.7	2.9	3.7	4.4	5.6	3.4	2.8	2.9
Foreign	83.0	61.0	60.2	61.7	55.8	64.3	68.7	68.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Share of Worldwide Pre-Tax Income								
U.S. Federal	8.6	18.9	19.5	18.4	19.5	16.8	15.3	15.5
U.S. State and Local	1.0	1.5	2.0	2.4	2.8	1.8	1.5	1.6
Foreign	46.6	32.0	32.1	33.5	28.2	33.4	36.9	37.8
Total	56.3	52.8	53.4	54.2	50.5	52.0	53.7	54.9

Note: Sum of components may not equal total due to independent rounding.
Source: Form EIA-28.

Domestic

Though aggregate domestic income taxes increased only slightly (less than $0.2 billion) in 1984, some lines of business incurred significant tax expense increases. Most of the increases were due to improved profit results in nonenergy sectors, mainly chemicals. The most rapid rate of increase in U.S. economic growth in over 30 years resulted in an increased demand for chemicals and in a significant increase in operating revenues. The higher operating rates and somewhat lower feedstock costs resulted in improved margins, and contributed to a doubling of pre-tax income and to an increase in income taxes from $0.3 billion to $1 billion for that segment. Although tax expenses allocated to the remainder of the domestic nonenergy sector (which includes steel operations) remained negative, the size of the tax offset declined by $0.3 billion so that tax expenses attributed to the entire domestic nonenergy sector increased by about $1 billion.

In contrast, income taxes allocated to domestic petroleum fell by 4 percent, or $0.5 billion. The decrease was attributable entirely to the refining/marketing segment since tax expenses for each of the other petroleum segments increased. Although refinery output, capacity utilization, and product sales all increased, weakness in product prices contributed to losses and to a negative tax expense. As a result, domestic refining/marketing taxes fell by $1.1 billion.

Income taxes for the domestic coal line of business increased by $0.2 billion as FRS companies' U.S. production increased sharply. Negative tax offsets in the nuclear area increased nearly $0.1 billion, as losses continued to rise. However, these decreases were offset by increased taxes on other energy operations, principally geothermal and tar sands extraction.

Foreign

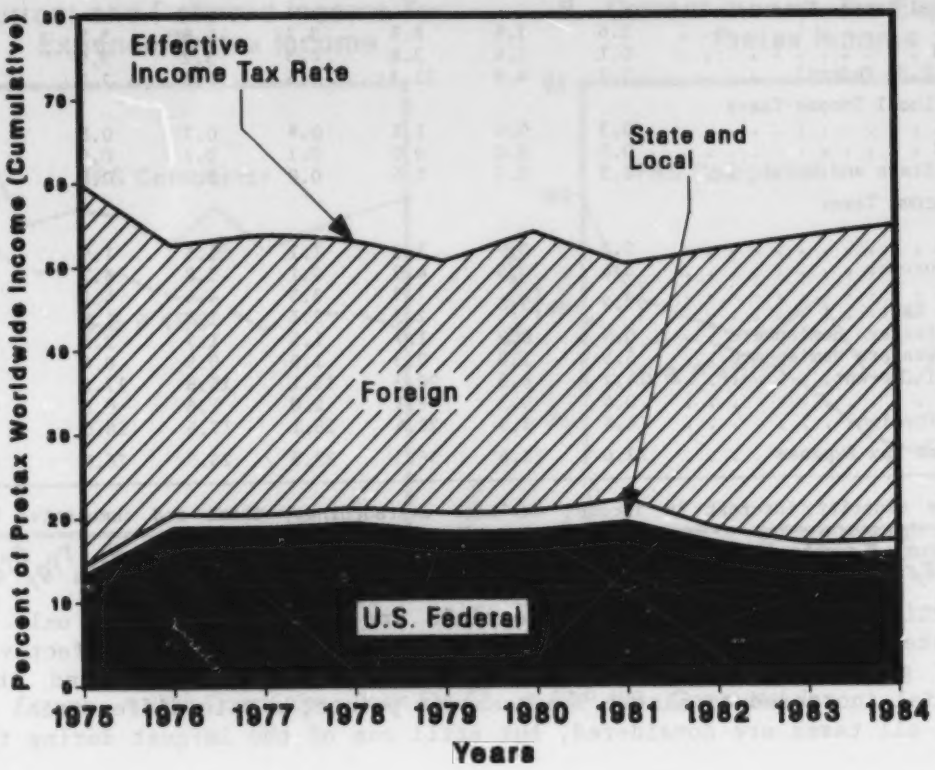
FRS companies' foreign income taxes increased by $0.5 billion, to $18.0 billion. The increase reflects the improved performance in oil and gas production operations. Taxes allocated to the refining/marketing segment fell (by $0.2 billion) as they did in the United States. However, this reduction was swamped by a rapid improvement in the production segment where tax expenses increased by $1.3 billion. Performance in foreign chemicals also improved, for the same reasons as in the United States, and further contributed to the increase in foreign tax expenses. As a consequence, for the third successive year the share of foreign income tax expenses relative to worldwide pre-tax income and relative to domestic tax collections increased (Figure 9).

The geographic distribution of foreign income taxes changed little in 1984 (Table 14). These geographically allocated taxes are available only for current taxes, which typically exceed 90 percent of all foreign income taxes. Their distribution reflects the diversification of foreign sources of crude oil supply. In 1984, production of crude oil increased in each of the six geographical areas into which foreign operations are divided. The two areas with the largest increases in production--the "Other Eastern Hemisphere" and the European component of the Organization of Economic Cooperation and Development (OECD)--were also the areas where taxes increased the most. The increases in OECD Europe production and taxes reflect a higher level of activity in the North Sea. Approximately one-third of foreign crude oil production and current tax expenses were in OECD Europe in 1984 and about one-fourth were in Africa. These shares and those for the other foreign areas were approximately the same in 1984 as a year earlier.

Effective Tax Rates

The current and deferred income tax expenses of the FRS companies have exceeded one-half of their pre-tax income for at least the past decade. Their effective income tax rates have continually exceeded those for the S&P 400 group of companies (Figure 10). Much of the difference reflects the greater degree of foreign operations by the FRS companies and the higher effective rates on such operations. In 1984, the FRS rate increased for the third successive year while the S&P 400 rate declined for the second successive year. The resultant 54.9 percent rate for FRS companies exceeded the S&P 400 rate by nearly 12 percentage points. This was the largest differential since at least 1974, the first year for which data are available for FRS companies.

Figure 9. Income Tax Shares in Worldwide Pre-Tax Income, FRS Companies, 1975 - 1984



Source: Form EIA-28.

Table 14. Composition of Income Tax Expense for FRS Companies, Selected Years, 1974 to 1984

Income Tax Sources	1974	1976	1980	1982	1983	1984	Percent Change from 1983
	(billion dollars)						
Pretax Income[a]	31.3	25.9	66.9	45.2	47.4	47.6	0.4
U.S. Federal Income Taxes							
Current	2.6	3.5	8.8	3.3	4.0	3.5	-13.0
Deferred	0.1	1.4	3.6	4.3	3.2	3.9	19.9
Total U.S. Federal	2.7	4.9	12.3	7.6	7.3	7.4	1.6
State and Local Income Taxes							
Current	0.3	0.4	1.5	0.8	0.7	0.8	13.3
Deferred	0.0	0.0	0.0	0.1	0.1	0.0	-80.5
Total State and Local	0.3	0.4	1.6	0.8	0.7	0.8	6.3
Foreign Income Taxes							
Current							
Canada	0.7	0.7	1.3	1.1	1.5	1.9	27.1
OECD Europe	0.4	0.5	4.9	3.1	5.8	6.2	6.8
Africa	(	(	7.9	3.5	4.4	4.1	-5.2
Middle East	(7.2	(5.0	2.3	2.5	1.8	1.8	5.0
Other Eastern Hemisphere	0.5	0.9	1.7	1.5	1.5	2.3	52.7
Other Western Hemisphere	5.5	1.0	2.3	1.5	0.9	0.8	-10.3
Total Current	14.2	8.0	20.3	13.1	15.8	17.2	8.6
Deferred	0.4	0.3	2.1	2.0	1.6	0.8	-53.4
Total Foreign	14.6	8.3	22.4	15.1	17.5	18.0	2.8
Total Income Tax Expense	17.6	13.6	36.3	23.5	25.5	26.1	2.6

[a]Includes minority interest in income; excludes extraordinary items and cumulative effect of accounting changes.

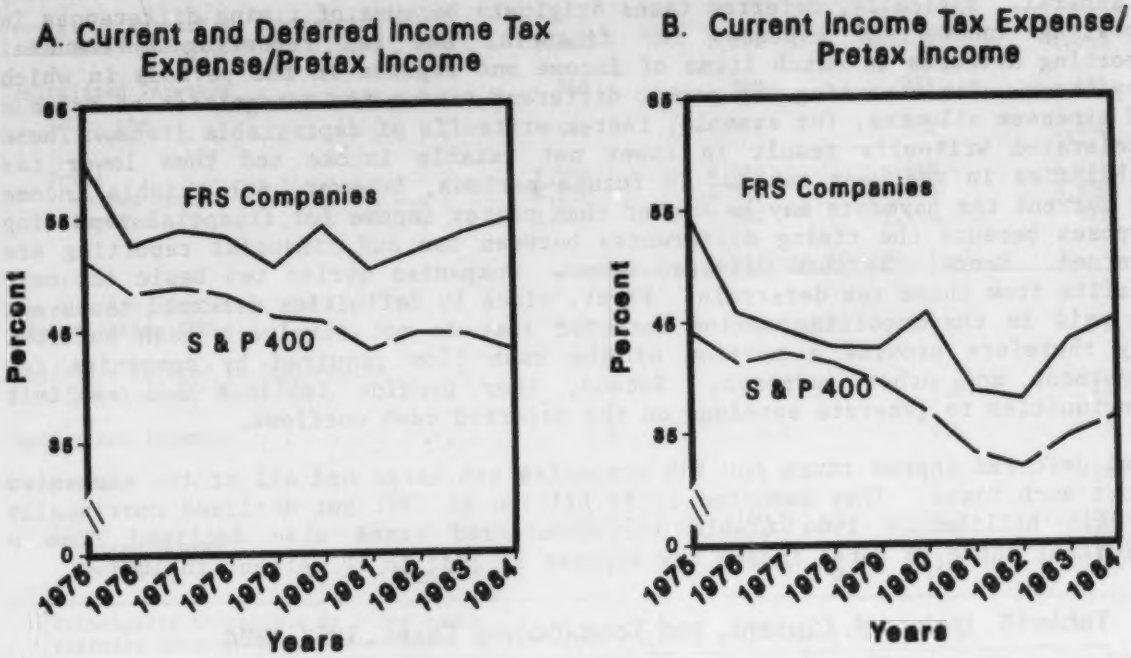
Note: Sum of components may not equal total due to independent rounding.

Source: Form EIA-28.

The effective rate levels and differentials are much smaller when only current income taxes are considered (Figure 10, Part B). In 1984, the effective rates for both groups of companies calculated on this basis rose and the rate differential increased to almost 9 percentage points, a rate differential smaller than when all taxes are considered, but still one of the largest during the past decade.

Effective foreign income tax rates for the consolidated foreign operations of FRS companies greatly exceeded effective U.S. rates on domestic operations. Highly reliable estimates of these rates cannot be made because of data limitations. However, rough estimates indicate that, based on current and deferred income taxes, the weighted average of foreign rates (using pre-tax income as weights) may have increased from about 65 percent in 1983 to 67 percent in 1984 while domestic rates remained at about 40 percent. The increase in the foreign rate is attributable to increased rates in both petroleum and the aggregate of non-petroleum lines of business.

Figure 10. Worldwide Effective Income Tax Rates for FRS Companies and S&P 400, 1975-1984



Source: • FRS Companies - Form EIA-28. • S&P 400 - Compustat, Inc.

Deferred Income Taxes

Deferred taxes are differences between tax obligations incurred under general accounting principles for financial reporting purposes and taxes actually payable in the reporting period. They originate from a variety of sources and are important to the financial operations of energy companies as well as to industry in general. Basically, deferred taxes originate because of timing differences in reporting income and expenses for financial and tax reporting. Financial reporting attempts to match items of income and expense in the periods in which they occur. Tax reporting may permit different timing for recognition of revenue and expenses allowing, for example, faster writeoffs of depreciable items. These accelerated writeoffs result in lower net taxable income and thus lower tax liabilities in the year taken. In future periods, however, net taxable income and current tax payments may be higher than pretax income for financial reporting purposes because the timing differences between tax and financial reporting are reversed. Hence, the term deferred taxes. Companies derive two basic economic benefits from these tax deferrals. First, since by definition deferred taxes are not paid in the reporting period incurred they do not involve a cash outflow. They therefore provide a portion of the cash flow required by companies for investment and other purposes. Second, they provide implicit and explicit opportunities to generate earnings on the deferred cash outflows.

Total deferred income taxes for FRS companies are large and all of the companies report such taxes. They amounted to $7 billion in 1981 but declined continually to $4.6 billion in 1984 (Table 15). Deferred taxes also declined from a 23-percent share in total income tax expense in 1981 to 18 percent in 1984.

Table 15. Deferred, Current, and Total Income Taxes, 1981-1984

Tax Component	1981	1982	1983	1984
	(million dollars)			
Deferred	6,964	6,318	4,929	4,648
Current	23,106	17,178	20,532	21,467
Total	30,070	23,497	25,461	26,115
	(percent distribution)			
Deferred	23.2	26.9	19.4	17.8
Current	76.8	73.1	80.6	82.2
Total	100.0	100.0	100.0	100.0

Note: Sum of components may not equal total due to independent rounding.
Source: Form EIA-28.

Three important sources of deferred taxes for FRS companies are depreciation, depletion and amortization (DD&A); provisions related to exploration and development; and capitalized interest (Table 16). Generally, deferred taxes generated from DD&A reflect the use of accelerated depreciation methods for tax reporting purposes. More particularly, deferred taxes generated from DD&A reflect principally financial and tax reporting differences in depreciation rates and expected lives, and differences in expensing and capitalization of expenditures. DD&A deferred taxes exceed those from any other single source and from all other sources combined. Further, the importance of this source grew rapidly in both absolute and relative importance between 1981 and 1983, though not sufficiently to offset the downward trend for the total deferred taxes. In

Table 16. Sources of Deferred Income Taxes for FRS Companies, 1981-1984

Source	1981	1982	1983	1984
	(million dollars)			
Depreciation, Depletion and Amortization (DD&A)	3,440	4,585	4,966	4,557
Provisions Related to Exploration and Development (E&D)[a]	2,868	2,392	475	1,050
Capitalized Interest	248	390	321	181
Other Items[bc]	408	-1,048	-832	-1,140
Total	6,964	6,318	4,929	4,648
United States	5,510	4,336	3,279	3,878
Foreign	1,454	1,982	1,650	770
	(percent distribution)			
Depreciation, Depletion and Amortization (DD&A)	49.4	72.6	100.8	98.0
Provisions Related to Exploration and Development (E&D)	41.2	37.9	9.6	22.6
Capitalized Interest	3.6	6.2	6.5	3.9
Other Items	5.9	-16.6	-16.9	-24.5
Total	100.0	100.0	100.0	100.0
United States	79.1	68.6	66.5	83.4
Foreign	20.9	31.4	33.5	16.6

[a]Principally intangible drilling costs.
[b]Includes unknown amounts that apply to the other individually listed categories.
[c]The values for this category were adjusted so that the sum for all categories add to the totals shown. Data for the individual categories are from company annual reports. Totals are from the FRS system.

Notes: Sum of components may not equal total due to independent rounding. Du Pont and U.S. Steel are not included as FRS companies until 1982.

Sources: •Company annual reports for the reporting year shown except for totals (including United States and Foreign) and "other items". •Totals are from Form EIA-28. •Other items are calculated as the difference between total and the sum of the first three deferred tax components shown.

1981, deferred taxes generated from DD&A amounted to $3.4 billion and accounted for 49 percent of all deferred taxes reported by FRS companies in that year. In 1983, they amounted to $5.0 billion (or about 100 percent). In 1984, they declined by $0.4 billion.

The increases in the amount of deferred taxes generated from DD&A during the 1981 to 1983 period reflect two developments. One is the implementation of the legislated Accelerated Cost Recovery System (ACRS) for tangible property placed in service after 1980. The other is mergers and acquisitions. The recovery periods for most assets covered by the ACRS tax system are based on a shorter tax life than accounting life and as a result the depreciation schedules are accelerated. The increased difference between tax depreciation allowances and financial reporting depreciation allowances gave rise to increased deferred taxes during at least the 1981-1983 period. The replacement of Conoco and Marathon by Du Pont and U.S. Steel, respectively, as FRS companies beginning in 1982 also greatly increased the amount of DD&A deferred taxes. The $0.4 billion fall in DD&A deferred taxes between 1983 and 1984 in part reflects a reversal of timing

differences for short-life property and the effects of the Tax Equity and Fiscal Responsibility Act of 1982, which curtailed some of the accelerated provisions of the ACRS. The reversal reflects the fact that, generally, deferred taxes are ultimately paid. However, as long as FRS companies continue their investment patterns and the modified ACRS system remains in effect DD&A deferred taxes will remain large. An extended slowdown in investment would substantially reduce the generation of deferrals, thus creating the potential for taxable income exceeding pretax income for financial reporting purposes. Thus, this source of funds would become a use of funds.

Tax laws allow energy producers, principally oil and gas producers, to expense on a current basis certain exploration and development costs which for financial accounting purposes must be capitalized and written off over a period of time. These exploration and development expenditures constitute the second largest source of deferred taxes for FRS companies. These expenditures consist principally of intangible drilling costs (IDCs). IDCs are costs incurred in developing and drilling oil, gas, and geothermal wells up to the point of production. They include costs such as labor, fuels, and site preparation. They exclude the cost of acquiring the property itself, as well as costs such as pipelines and other tangible facilities to control and transport the oil and gas produced. About 70 percent of U.S. industry costs of developing and drilling for oil and gas is estimated to be IDCs.

IDCs can result in tax deferral since, for tax purposes, the taxpayer has the option (with the exception noted later) of expensing the IDCs in the year incurred or of capitalizing them for subsequent amortization.[4] Also, prior to the Tax Reform Act of 1984, prepaid IDCs were fully deductible. This generated deferred taxes since all FRS companies are on an accrual basis for financial reporting purposes.

Deferred taxes generated by exploration and development expenditures (principally IDCs) for FRS companies fell from about $2.9 billion in 1981 to $0.5 billion in 1983, but increased to $1.0 billion in 1984. As a share of total deferred taxes for FRS companies, the fall was from 41 percent in 1981 to about 10 percent in 1983, but increased to about 23 percent in 1984. Two factors account for most of the fall. First, integrated oil companies were required to capitalize 15 percent of their IDC expenditures for tax purposes after 1982.[5] Prior to that time they had not been required to capitalize. Second, FRS companies' IDC expenditures fell sharply in 1983, in response to declining crude oil prices and falling costs of drilling and equipping wells.

Differences between financial and tax accounting of interest expenditures, particularly expenditures for multiperiod production investments, are a third source of deferred taxes. Deferred taxes generated from this source consistently accounted for less than 7 percent of FRS companies' annual deferred taxes during the 1981-1984 period.

There are many additional sources of deferred taxes. They are presented collectively as "other items" in Table 16. The aggregate value for "other items" was large and negative each year during the 1982-1984 period. The shift from positive to negative deferred taxes from 1981 to 1982 to a large extent reflects the effects of mergers and acquisitions on the composition of the FRS group of companies.

Deferred income taxes provide FRS companies with a significant source of funds for investment and other purposes. These taxes were the third leading source of funds from operations during the 1981-1984 period, exceeded only by net income and DD&A (Table 17). In 1981, they accounted for over 12 percent of these funds and in 1984 for nearly 8 percent.

Table 17. Deferred Income Taxes and Funds from Operations, 1981-1984

Funds	1981	1982	1983	1984
	(million dollars)			
Total Deferred Taxes	6,964	6,318	4,929	4,648
	(percent distribution)			
Funds from Operations				
Deferred Taxes Recognized	12.5	11.0	7.6	7.7
Net Income	48.7	36.1	36.1	33.5
Depreciation, Depletion, and Amortization	31.2	39.6	43.7	45.9
Dry Hole Expense	9.0	10.9	8.0	6.9
Other	-1.4	2.4	4.6	6.0
Total	100.0	100.0	100.0	100.0

Source: Form EIA-28.

Non-Income Taxes

The FRS companies pay many taxes in addition to income taxes. Comprehensive data for these non-income taxes are available only for those paid to domestic authorities. The most important of these are the WPT and severance taxes. The WPT is a Federal tax whereas the severance taxes are almost exclusively State taxes. The WPT is applied to domestically produced crude oil and severance taxes are applied to the extraction of natural resources, mainly energy. The only other large domestic non-income tax expenses incurred by FRS companies are generic rather than energy-specific and are limited principally to payroll taxes and to sales, use, and property taxes.

FRS companies' U.S. non-income taxes declined rapidly both in dollar terms and relative to other taxes since 1981 (Table 18). In 1981, they amounted to $26.1 billion. By 1984, they had fallen to $15.7 billion, or to $2.1 billion less than a year earlier. In 1981, domestic non-income taxes were twice as great as domestic income taxes. In 1984, they were only 91 percent greater. Further, the share of U.S. non-income taxes in total worldwide tax expense (exclusive of foreign non-income taxes) declined from 46 percent in 1981 to 38 percent in 1984. The largest single component in the decline in FRS companies' non-income taxes since 1981 has been WPT expenses. Between 1983 and 1984, the fall in WPT expenses accounted for one-half of the $2.1 billion decrease in non-income taxes. The remainder was accounted for almost entirely by decreases in payroll and miscellaneous other non-income taxes. Severance taxes, which had fallen continually between 1981 and 1983, principally because of declining crude oil prices and declining aggregate crude oil and natural gas production, were virtually unchanged in 1984 as crude oil prices fell by only a small amount, natural gas prices at the wellhead stabilized, and aggregate production of crude

oil and natural gas increased somewhat.[6] Most of the FRS companies' severance taxes result from extracting crude oil and natural gas and relatively little from producing coal and uranium.

Table 18. Additional Domestic Tax Liabilities of FRS Companies, 1981-1984
(Billion Dollars)

Tax Category	Total				Petroleum			
	1981	1982	1983	1984	1981	1982	1983	1984
Windfall Profit Tax	16.9	10.7	6.9	5.7	16.9	10.7	6.9	5.7
Severance Tax	4.1	3.8	3.6	3.7	4.0	3.7	3.4	3.5
Other[a]	5.1	6.1	7.4	6.3	3.2	3.4	4.6	3.6
Total	26.1	20.6	17.8	15.7	24.1	17.8	14.9	12.8

[a]Payroll, sales, use, property, import duties, etc.
Note: Sum of components may not equal total due to independent rounding.
Source: Form EIA-28.

The rapid fall in FRS companies' WPT taxes reflects the operation of specific provisions of the law. The Crude Oil Windfall Profit Tax Act of 1980 provides for an excise tax on the windfall profit from the first sale of taxable domestic crude oil extracted on or after March 1, 1980. The windfall profit is the difference between two prices. The first is the selling price of the crude oil. The second is the sum of an inflation-adjusted base price for the oil as established by the Act and the producer's state severance tax liability on the windfall profit per barrel. A WPT rate is applied to this difference. The base price and the tax rate vary according to the class of the producer (major or independent) and the category (or tier) of oil produced. Generally, the tax is designed to provide the Federal treasury with most of the increased revenues on old oil resulting from price decontrol and the pricing policies of OPEC while providing sufficient incentive to find and produce new oil.

During the 10 months of 1980 in which the WPT was in effect, FRS companies incurred $5 billion of WPT liabilities to the U.S. Treasury. These liabilities more than tripled in 1981, to $16.9 billion, but then decreased continually to $5.7 billion in 1984. Total U.S. industry WPT liabilities followed a pattern similar to that for FRS companies (Table 19). The share of FRS companies' WPT expenses in the total for all U.S. industry has been relatively constant at about two-thirds except for the first year the tax was in effect.

Table 19. Crude Oil Windfall Profit Tax Liabilities of FRS Companies and U.S. Industry, 1980-1984

Group	1980	1981	1982	1983	1984
	(billion dollars)				
FRS Companies	5.0	16.9	10.7	6.9	5.7
U.S. Total	9.9	25.9	16.8	10.7	8.9
	(percent)				
FRS Share in U.S. Total	50.5	65.3	63.7	64.5	64.0

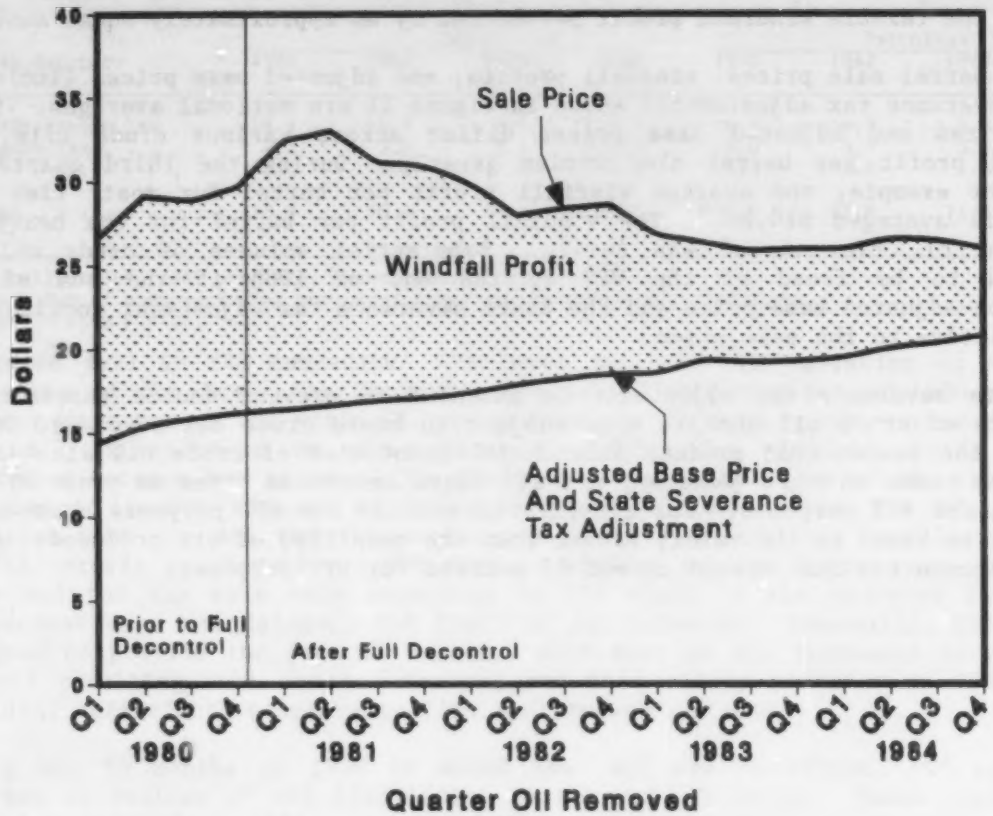
Sources: •Form EIA-28 except for U.S. totals. •U.S. totals through 1983 are from Statistics of Income Bulletin, Internal Revenue Service, Department of the Treasury, Vol. 5, No. 1, Summer 1985, p. 84. •U.S. industry data for 1984 are preliminary and were supplied by the Department of the Treasury.

The decrease in WPT liabilities reflects the rapid fall in windfall profits.[7] The fall in windfall profits since 1981 is the result of a decline in the price at which crude oil is first sold and rising inflation-adjusted base prices (Figure 11). Between 1983 and 1984, the sale price per barrel for all U.S. industry was virtually constant but the combined inflation-adjusted base price and severance tax adjustment increased by an estimated $1.11 per barrel. This reduced the taxable windfall profit per barrel by an approximately equal amount.

The per barrel sale prices, windfall profits, and adjusted base prices (including State severance tax adjustments) shown in Figure 11 are national averages. Since sale prices and adjusted base prices differ across various crude oils, the windfall profit per barrel also varies greatly. During the third quarter of 1984, for example, the average windfall profit per barrel for most "tier one" crude oil averaged $10.24.[8] The windfall profit per barrel for the heavy oil component of "tier three" was $0.42. Substantial volumes of crude oil are expected to be freed of the WPT by the end of 1985 if the sum of the inflation-adjusted base price and the State severance tax adjustment continues to rise relative to the sale price.

The State severance tax adjustment is intended to prevent double taxation for producers of crude oil who are also subject to State crude oil severance taxes. Most of the States that produce substantial quantities of crude oil also impose severance taxes on oil. However, not all State severance taxes on crude oil are eligible for WPT purposes. For example, to qualify for WPT purposes a severance tax must be based on the value, rather than the quantity, of oil produced. Also, the severance tax rate cannot exceed 15 percent for WPT purposes.

Figure 11. Sale Price, Adjusted Price, and Windfall Profit per Barrel for U.S. Industry, 1980-1984



Source: Internal Revenue Service, Department of the Treasury, Statistics of Income Bulletin (Summer 1985 and earlier issues). Data for fourth quarter 1984 are preliminary and were supplied by the Department of the Treasury.

Footnotes to Chapter 3

[1]Ratios of income taxes to pretax incomes are referred to as effective income tax rates in contrast with legislated or statutory rates. All income tax rates in this chapter are effective rates unless otherwise indicated.

[2]Comprehensive foreign non-income tax data are not collected by the FRS system but these taxes are estimated to have exceeded $3 billion in 1984.

[3]Current income taxes are those actually incurred and payable during the current period. Deferred taxes, although incurred during the current period and treated under generally accepted accounting principles as if paid during that period, are payable at some future date. See the section below and Appendix E for a discussion of deferred taxes.

[4]Taxpayers may also elect to expense only IDCs for dry wells and to capitalize them on productive wells.

[5]The Tax Reform Act of 1984 increased that percentage to 20 percent for expenditures after 1984. See Appendix H for a discussion of the energy specific provisions of the Act. The provisions apply not only to IDC expenditures but also to the Windfall Profit Tax, percentage depletion, taxes on export sales, capital gains and to other tax related matters. The net effect of the energy specific provisions on the aggregate tax burden of energy companies is small relative to their present tax liabilities.

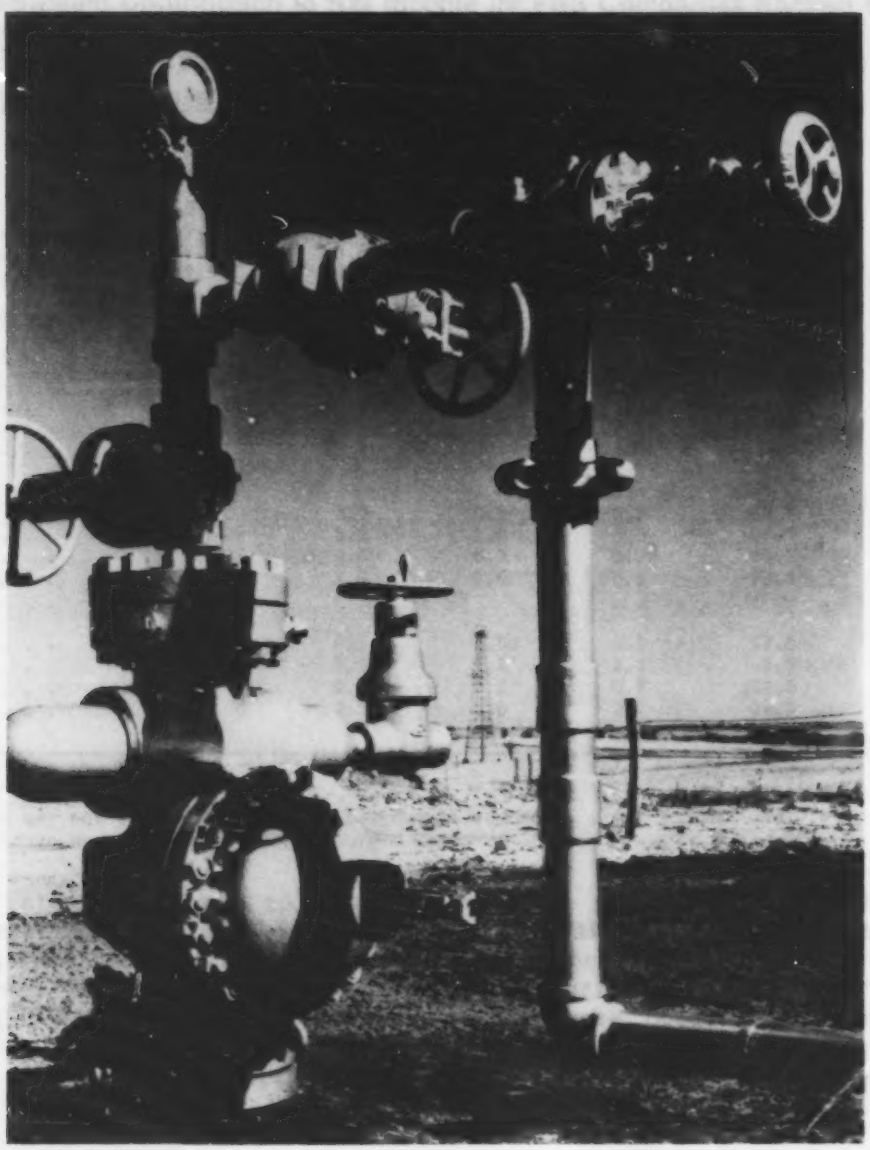
[6]Most crude oil and natural gas severance taxes are levied as a percentage of the value of the resource (an ad valorem tax). Most coal severance taxes are estimated to be levied on the quantity of coal removed (a specific tax).

[7]The decrease also reflects some adjustment in tax rates.

[8]Domestically produced crude oil is classified into three tiers for purposes of the WPT. Tier one consists of all domestically produced crude oil other than oil classified in tiers two or three, or explicitly exempted by law from the tax. Tier two oil is any oil from a stripper well property within the meaning of the June 1979 Department of Energy pricing regulations and oil from a U.S. economic interest in a Naval Petroleum Reserve. Tier three oil has three components: heavy oil, incremental tertiary oil, and newly discovered oil.

Chapter 4

Domestic Petroleum Developments



Christmas Tree

Chapter 4

Domestic Petroleum Developments

4. Domestic Petroleum Developments

The FRS companies' net income from domestic petroleum operations totaled $15.8 billion in 1984, down 0.3 percent from 1983, and 20.3 percent from the peak year of 1981 (Table 20). A sharp deterioration of earnings from refining/marketing operations, from $1.6 billion to $0.1 billion, accounted for the decrease in overall domestic petroleum net income.[1] No FRS group was spared difficulty. The top four group reported net losses. However, improved earnings from other petroleum activities offset most of the refining/marketing decline (Table 20). Increases in the FRS companies' U.S. production of oil and gas led to a modest rebound in upstream earnings, from $12.2 billion in 1983 to $13.3 billion in 1984. Net income from regulated pipelines rose from $2.0 billion in 1983 to $2.5 billion in 1984. The latter improvement was concentrated among the smaller companies, reflecting the financial contribution of pipelines acquired in 1983.

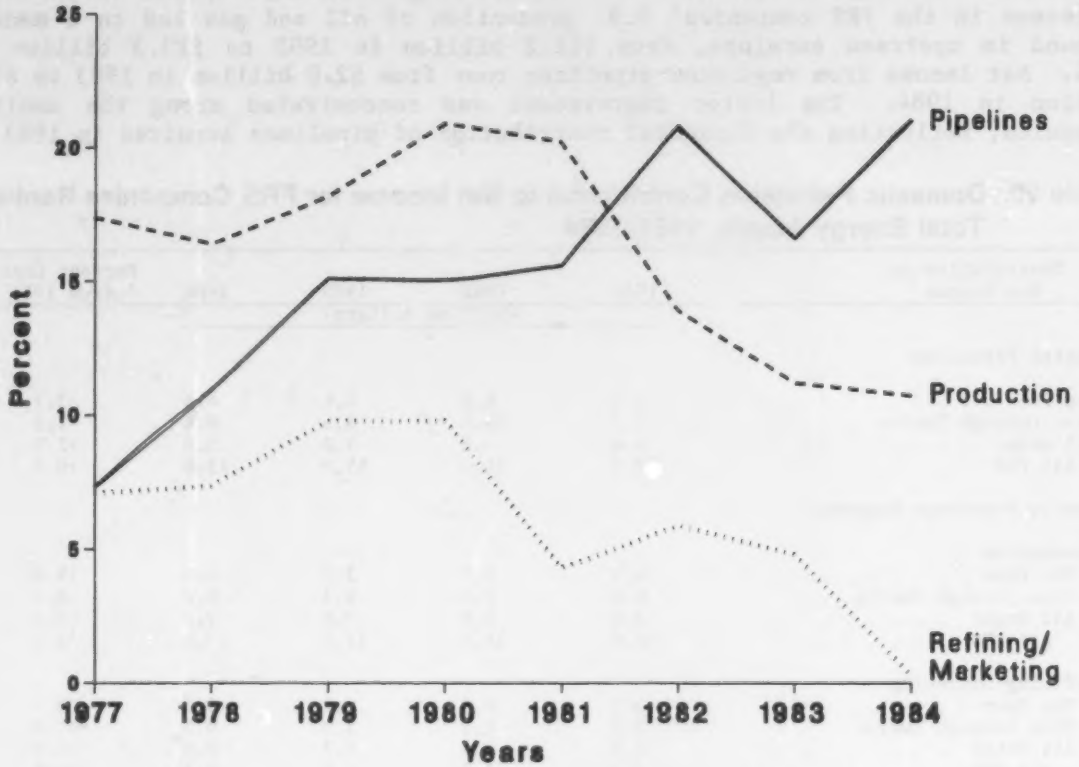
Table 20. Domestic Petroleum Contribution to Net Income for FRS Companies Ranked by Total Energy Assets, 1981-1984

Contribution to Net Income	1981	1982	1983	1984	Percent Change from 1983
	(billion dollars)				
Domestic Petroleum					
Top Four	5.7	4.5	4.4	4.5	3.7
Five through Twelve	9.7	10.0	8.5	8.4	-1.5
All other	4.4	3.8	3.0	3.0	-2.5
All FRS	19.9	18.3	15.9	15.8	-0.3
Domestic Petroleum Segments					
Production					
Top Four	4.9	3.7	3.5	4.2	19.6
Five through Twelve	8.0	7.3	6.3	6.8	8.7
All Other	3.8	3.2	2.5	2.3	-7.6
All FRS	16.8	14.1	12.2	13.3	8.5
Refining/Marketing					
Top Four	0.3	0.3	0.3	-0.3	NM
Five through Twelve	0.6	1.2	1.0	0.3	-67.9
All Other	0.3	0.4	0.3	0.0[a]	-88.9
All FRS	1.3	1.9	1.6	0.1	-93.6
Pipelines					
Top Four	0.5	0.5	0.5	0.6	12.6
Five through Twelve	1.1	1.5	1.2	1.2	1.2
All Other	0.2	0.3	0.2	0.6	166.8
All FRS	1.8	2.3	2.0	2.5	24.0

[a]Less than $50 million.
NM = Not meaningful.
Note: Sum of components may not equal total due to independent rounding, eliminations, and nontraceables. Percent change was calculated from unrounded data.
Source: Form EIA-28.

The FRS companies' rates of return to domestic oil and gas production and domestic refining/marketing fell to their lowest levels in the 1977-1984 period (Figure 12). Although net income from domestic oil and gas production increased over 8 percent between 1983 and 1984, the asset base increased even faster resulting in a slight fall in the rate of return to these operations. In domestic refining/marketing operations, the benefits of increased refinery output and refined product sales, together with lower raw material input prices, were

Figure 12. Profit Rates in Domestic Petroleum Segments for FRS Companies, 1977-1984[a]



aMeasured as contribution to net income/net investment in place.

Source: Form EIA-28.

not sufficient to offset decreased gasoline and distillate prices. As a result, the rate of return to the FRS companies' domestic refining/marketing operations fell sharply in 1984. In contrast to the results for the FRS companies, public non-FRS oil and gas producers and refiner/marketers showed a rebound in profitability in 1984 (Figure 13).[2] However, profit rates for these latter companies were still low in comparison to pre-1982 profit rates.

Oil and Gas Production

Sales and Income

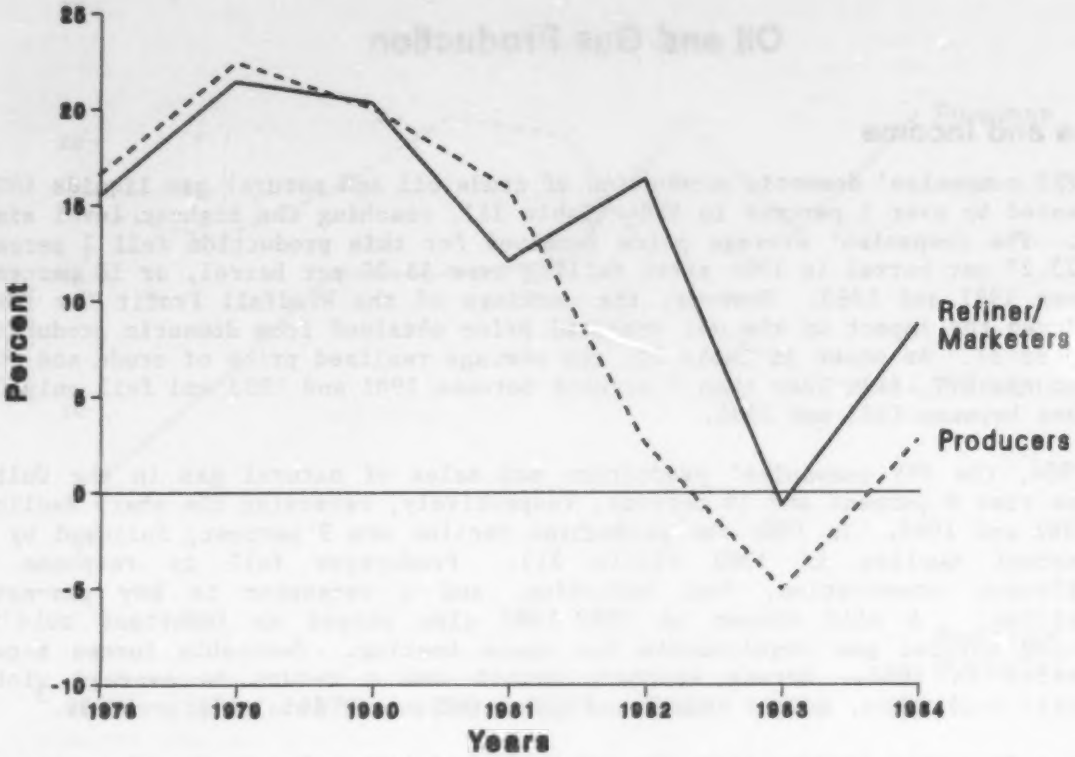
The FRS companies' domestic production of crude oil and natural gas liquids (NGL) increased by over 1 percent in 1984 (Table 21), reaching the highest level since 1978. The companies' average price received for this production fell 2 percent to $23.27 per barrel in 1984 after falling over $5.00 per barrel, or 18 percent, between 1981 and 1983. However, the workings of the Windfall Profit Tax (WPT) cushioned the impact on the net realized price obtained from domestic production (Chapter 3). As shown in Table 21, the average realized price of crude and NGL, net of the WPT, fell less than 5 percent between 1981 and 1983 and fell only 0.1 percent between 1983 and 1984.

In 1984, the FRS companies' production and sales of natural gas in the United States rose 8 percent and 16 percent, respectively, reversing the sharp declines of 1982 and 1983. In 1982 the production decline was 9 percent, followed by an 11-percent decline in 1983 (Table 21). Production fell in response to significant conservation, fuel switching, and a recession in key gas-using industries. A mild winter in 1982-1983 also played an important role in reducing natural gas requirements for space heating. Favorable forces became operative in 1984. Strong economic growth and a return to average winter climatic conditions, raised demand and moderated supply imbalance problems.[3]

Another favorable factor, from the standpoint of increasing consumption, was the slower rate of increase in natural gas prices in 1984. For the FRS companies, the average natural gas sales price rose only 3 percent, following rises of 21 percent and 8 percent in 1982 and 1983, respectively. As a result, consumption fell by 7 percent in both 1982 and 1983. Despite the modest increase in natural gas prices in 1984, the FRS companies' revenue from natural gas sales increased by nearly $4 billion, as their volume of natural gas sales was 16 percent greater than the prior-year level.

Total revenues (net of the WPT) from the FRS companies' domestic oil and gas operations rose $3.9 billion in 1984, to $71.2 billion, as a result of increased oil and gas sales and a $1.2-billion drop in WPT payments. This revenue gain more than offset a $2.6-billion increase in operating costs (Table 22). As a result, operating income from domestic oil and gas operations rose nearly 6 percent in 1984. Among the cost categories shown in Table 22, charges for depreciation, depletion, and amortization (DD&A) accounted for $1.3 billion of increased costs. This increase is related to the high levels of exploration and development investment evident since 1979. The largest component of costs was lifting costs (the cost of extracting oil and gas from producing wells), which

Figure 13. Net Income as a Percent of Stockholders' Equity for Publicly Traded Non-FRS Oil and Gas Producers and Refiner/Marketers, 1978-1984



Source: Standard & Poors' Compustat Services, Inc.

Table 21. Average Prices, Sales, and Production in Domestic Oil and Gas for FRS Companies, 1981-1984

Prices, Sales, and Production	1981	1982	1983	1984	Percent Change from 1983
Oil and Gas Production and Sales[a]					
Production Volumes					
Crude Oil and NGL (million barrels)	2,072.4	2,079.1	2,059.3	2,088.8	1.4
Dry Natural Gas (billion cubic feet)	9,161.4	8,316.3	7,365.3	7,946.0	7.9
Total (million barrels, COE[b])	3,694.8	3,552.7	3,364.4	3,496.8	3.9
Sales Volumes					
Crude Oil and NGL (million barrels)	2,307.5	2,278.5	2,297.1	2,301.3	0.2
Dry Natural Gas (billion cubic feet)	9,689.2	8,634.0	7,769.0	9,016.0	16.1
Total (million barrels, COE[b])	4,023.5	3,808.4	3,673.8	3,898.9	6.1
Unit Production Segment Sales Values					
Crude Oil and NGL (dollars per barrel)	29.09	26.03	23.82	23.27	-2.3
Crude Oil and NGL, Net of Windfall Profit Tax (dollars per barrel)	21.78	21.35	20.82	20.79	-0.1
Dry Natural Gas (dollars per 1,000 cubic ft.)	1.82	2.20	2.37	2.44	3.0

[a]Production is on a net ownership basis. Sales are domestic production segment sales. See Appendixes A and E for discussion of FRS reporting conventions.
[b]COE = Crude oil equivalent. Dry natural gas was converted at 0.1772 barrels of crude oil per 1,000 cubic feet for 1982-1984 and 0.1771 barrels for 1981.
Source: Form EIA-28.

rose $1 billion, or 6 percent, in 1984. Higher levels of oil and gas production were largely responsible for the increase. Oil and gas production (on a Btu-equivalent basis) rose 4 percent (Table 21) while unit lifting costs (net of the WPT) rose only 2 percent. Dry hole costs declined despite increased drilling activity. Although the number of exploratory dry holes increased 25 percent for the FRS companies in 1984, this increase in activity was more than offset by a 25-percent decline in cost per dry hole drilled.

Despite nearly 4 years of general decline in crude oil prices and a substantial moderation in gas price rises, the FRS companies' cash flow contribution from their domestic oil and gas operations appears to have been only modestly impaired. The last section of Table 22 presents operating income and its components on a unit basis (i.e., divided by oil and gas sales volumes on a crude oil equivalent basis). The contribution to cash flow is measured by adding to operating income the non-cash charges for exploratory dry holes and depreciation, depletion, and amortization (DD&A).[4] As can be seen in the last line of Table 22, contribution to cash flow per unit of sales fell only 1.2 percent in 1982, 0.4 percent in 1983, and remained constant in 1984.

Table 22. Components of Revenues and Costs in Domestic Oil and Gas Production for FRS Companies, 1981-1984

Revenues and Costs	1981	1982	1983	1984	Percent Change from 1983
	(billion dollars)				
Operating Revenues					
Crude Oil and NGL	67.1	59.3	54.7	53.6	-2.1
Natural Gas	17.7	19.0	18.4	22.0	19.3
Other	1.2	0.9	1.1	1.3	22.3
Operating Revenues	86.0	79.3	74.2	76.9	3.5
Windfall Profit Tax (WPT) Expense	16.9	10.7	6.9	5.7	-17.0
Revenues Net of WPT	69.2	68.6	67.3	71.2	5.6
Operating Expenses (Net of WPT)					
Depreciation, Depletion, and Amortization (DD&A)	9.3	11.4	13.1	14.4	9.9
Lifting Costs	15.8	17.6	17.9	18.9	5.8
Dry Hole Costs	3.1	4.3	3.0	2.8	-6.2
Geological and Geophysical Expenses	2.1	2.1	1.9	1.8	-6.2
Other	8.5	8.4	9.2	9.8	5.6
Total Operating Expenses (Net of WPT)	38.7	43.7	45.1	47.7	5.6
Operating Income	30.4	24.9	22.2	23.5	5.7
Per Unit Values for Domestic Production Segment[a] (dollars per barrel, COE[b])	(dollars per barrel)				
Operating Revenues (net of WPT)	17.17	17.70	18.33	18.25	-0.4
Operating Expenses (net of WPT)	9.61	11.28	12.28	12.23	-0.4
Operating Income	7.56	6.42	6.05	6.02	-0.5
Contribution to Pretax Cash Flow[c]	10.61	10.48	10.44	10.44	0.0

[a]Financial items are divided by domestic production sales volumes of oil and gas on a COE basis.
[b]COE = Crude oil equivalent. Dry natural gas was converted at 0.1772 barrels of crude oil per 1,000 cubic feet for 1982-1984 and 0.1771 barrels for 1981.
[c]Sum of operating income, DD&A, and dry hole costs divided by domestic production sales volumes of oil and gas on a COE basis.
Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.
Source: Form EIA-28.

Upstream Petroleum Investments

Including the purchase value of mergers, the FRS companies' reported capital outlays for domestic petroleum show an increase of over $20 billion in 1984. However, $18.6 billion of outlays reflect the value of assets transferred through mergers. To better understand the characteristics of new investment in oil and gas operations, subsequent discussion focuses on capital outlays adjusted for 1984 intra-FRS companies merger purchase values. It should be noted that approximately $2.5 billion of the remaining reported domestic oil and gas production outlays reflect acquisitions of non-FRS company assets by Phillips Petroleum, Sun, and U.S. Steel (see Chapter 2).

In 1984, U.S. exploration and development activity increased. The monthly average rotary rig count was 9 percent above the 1983 level and estimated well completions exceeded prior-year levels by 11 percent.[5] The FRS companies were major participants in this upswing, increasing their capital outlays for domestic oil and gas production by 13 percent, to $24.5 billion in 1984 (Table 23 and Figure 14).

Table 23. Additions to PP&E in Domestic Petroleum for FRS Companies Ranked by Total Energy Assets, 1983-1984

Additions to PP&E	1983	1984	Adjusted[a] 1984	Percent Change	Adjusted[a] Percent Change
	(billion dollars)				
Domestic Petroleum					
Top Four	8.6	28.8	8.9	236.3	4.0
Five through Twelve	11.3	13.4	13.4	18.8	18.8
All Other	9.2	7.6	7.6	-17.2	-17.2
All FRS	29.0	49.8	29.9	71.5	3.2
Domestic Petroleum Segments					
Production					
Top Four	6.3	24.6	7.0	291.0	11.8
Five through Twelve	9.4	11.2	11.2	18.8	18.8
All Other	6.0	6.3	6.3	3.5	3.5
All FRS	21.7	42.1	24.5	93.1	12.8
Refining/Marketing					
Top Four	2.2	3.8	1.8	71.6	-19.4
Five through Twelve	1.6	1.8	1.8	14.1	14.1
All Other	1.4	1.2	1.2	-17.3	-17.3
All FRS	5.2	6.8	4.8	29.6	-10.2
Pipelines					
Top Four	0.1	0.4	0.1	521.4	38.5
Five through Twelve	0.2	0.4	0.4	50.1	50.1
All Other	1.7	0.1	0.1	-91.2	-91.2
All FRS	2.0	0.9	0.6	-55.3	-70.3

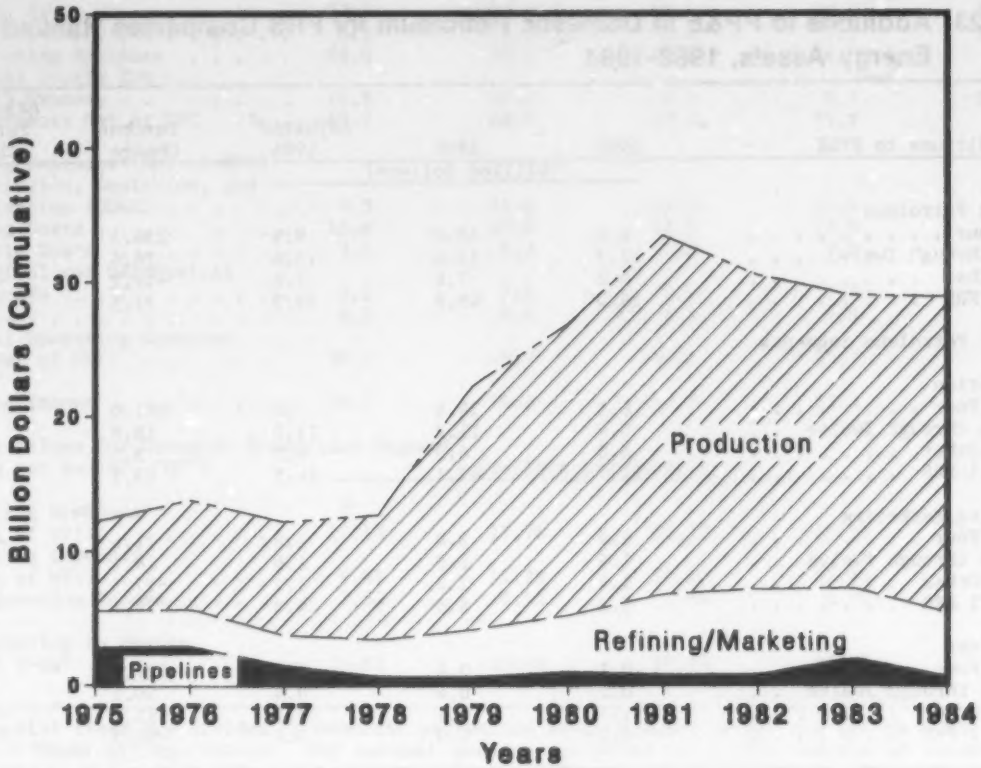
[a]Adjusted to exclude purchase value of existing assets associated with the mergers of Chevron with Gulf, Texaco with Getty Oil, and Mobil with Superior Oil.

Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.

Source: Form EIA-28.

The increase in exploration and development activity appears to be related to improvements in the spread between oil and gas prices and the cost of discovering and developing additional oil and gas supplies. That is, although crude oil prices declined, finding costs declined even more rapidly. For example, an analysis contained in Chapter 5 indicates that the unit value (in 1984 dollars) of reserve additions declined by $0.52 per barrel between 1983 and 1984, but finding costs per barrel declined by $1.52. It appears that the favorable economic developments of 1984 have not carried over to 1985. During the first 6 months of 1985, the average wellhead price of crude oil declined by $2 per barrel from the first 6 months of 1984, while wellhead natural gas prices remained

Figure 14. Additions to PP&E in Domestic Petroleum for FRS Companies, 1975-1984



Note: Merger purchase values are excluded from 1982 and 1984 data.

Source: Form EIA-28.

flat.[6] These declines paralleled reductions in exploration and development activity. For the first 6 months of 1985, estimated well completions were 6 percent below the comparable period in 1984 and the monthly average rotary rig count was down 13 percent.

Refining and Marketing

Financial and Operating Results

Domestic refining and marketing operations of the FRS companies suffered operating losses of $1 billion in 1984 (Table 24). This was the first year since 1975 in which the FRS companies as a group have experienced a loss in domestic refining and marketing. Total product sales volume increased by 4.1 percent over 1983 volume, but the average price for total refined products fell by 3.6 percent to $34.07 per barrel. As a result, refined product revenue increased by only 0.3 percent. Even though raw material input cost per barrel of refinery output fell by 3.4 percent in 1984 to an average of $25.92, marketing and other refinery expenses increased by 24 percent and 11 percent, respectively. As a result, the refined product margin fell to a mere $0.01 per barrel. Operating income fell to a loss of $1 billion, after netting DD&A, general and administrative, and TBA expenses.

Table 24. Sales, Expenses, and Income in Domestic Refining/Marketing for FRS Companies, 1982-1984

Sales, Expenses, and Income	1982	1983	1984	Percent Change 1982-1983	Percent Change 1983-1984
	(billion dollars)				
Refined Product Sales	162.7	149.9	150.4	-7.9	0.3
Other Revenues	74.6	74.0	70.3	-0.9	-5.0
Total	237.4	223.8	220.7	-5.7	-1.4
Operating Income	2.3	1.5	-1.0	-35.3	NM
Contribution to Net Income	1.9	1.6	0.1	-14.5	-93.6
Refined Product Sales (million barrels)	4,215.3	4,237.9	4,412.6	0.5	4.1
Per Unit Values for Domestic Refining/Marketing Segment					
	(dollars per barrel)				
Average Sales Price					
Gasoline	41.55	38.04	35.79	-8.4	-5.9
Distillate	39.71	35.37	34.37	-10.9	-2.8
Other	31.61	30.23	30.52	-4.4	1.0
All Refined Products	38.61	35.36	34.07	-8.4	-3.6
Raw Material Input Cost per Barrel of Refinery Output	29.49	26.84	25.92	-9.0	-3.4
Refined Product Margin[b]	0.85	0.71	0.01	-16.5	-98.6
Contribution to Pretax Cash Flow[a]	1.06	0.86	0.31	-18.9	-64.0

[a]Sum of domestic refining/marketing operating income and DD&A, divided by the volume of refined products sold.

[b]See Table G54 in Appendix G for the components to calculate the refined product margin.

Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.

Source: Form EIA-28.

The contrast in financial results of domestic refining and marketing as compared to exploration and production is exemplified by the differences in the contribution to cash flow per barrel of product sold. For example, Table 22 indicated that the contribution to cash flow in domestic oil and gas production held steady at $10.44 per barrel in 1984. The contribution to cash flow in domestic refining and marketing fell 64 percent in 1984 to $0.31 per barrel. In other words, on a per-barrel basis, the cash flow contribution from upstream operations was more than 30 times the cash flow contribution from downstream operations in 1984. Similar differences in magnitudes prevailed in 1982 and 1983.

The average product price fell by $1.29 per barrel, but the average refinery input price fell only $0.92 per barrel (Table 24). Combined with an increase in marketing expenses of $0.30 per barrel, operating margins were severely squeezed. The top four group (ranked by total energy assets) had an operating loss of $1 billion in 1984. Problems for this group were exacerbated since they were the only group to experience an increase in crude acquisition costs. All groups experienced declining product prices. While operating income for the five through twelve group fell by 87 percent, this was the only group to experience positive operating income in 1984 ($155 million). The all other group exhibited mixed refining and marketing results. While operating income was negative (-$176 million), after tax net income was a small but positive $36 million.

During 1984, 26 refineries were closed in the United States.[8] In the 1981-1984 period, the FRS companies closed 12 refineries with 754,900 barrels per day of distillation capacity or 29.9 percent of the total reported shut down by domestic industry in that period (Table 25). However, in 1984, although there were some ownership changes, there was no net change in the number (102) of FRS refineries reported on the Form EIA-28.

Refinery utilization rates, ordinarily a key indicator of profitability, have been edging up since 1981 for both the FRS companies and total industry. Nonetheless, utilization rates remain below the levels prevailing prior to 1979 when rates were above 85 percent. The FRS companies' utilization rate in 1984 was only 79.5 percent, up from 72.0 in 1981 (Table 26). The domestic industry (including Puerto Rico and the Virgin Islands) utilization rate increased from 68.3 to 75.4 over the same period (Figure 15).

Refinery Configuration

After excluding the purchase value of existing assets, additions to refining investment in place totaled $2.7 billion in 1984, down 26.0 percent from 1983 (Table 4 in Chapter 2). This expenditure was primarily to upgrade refineries to facilitate efficient use of lower quality crude oils, and to produce increased proportions of light products, such as distillate and gasoline. Over the past several years, most refinery investments have been for upgrading purposes. Industry experts view cracking and reforming capacity as key elements in refining economics because they allow flexible use of inputs and a flexible output slate that minimizes residual fuel oil output. Further, residual fuel oil may now be used as an input competitive with crude oil for the production of light products.

Table 25. Refineries Shut Down Since January 1, 1981, for FRS Companies and Domestic Industry

District/Company	Location	Crude Distillation Capacity	Total Downstream Capacity	Years in Operation
PAD District I				
Amoco Oil	Baltimore, MD	15,000	0	25+
Ashland Oil	Buffalo, NY	64,000	106,500	25+
Mobil Oil	Buffalo, NY	43,000	67,000	25+
FRS Total	-	122,000	173,500	
PAD Total	-	196,300	188,480	
FRS Share	-	62.2	92.1	
PAD District II				
Amoco Oil	Sugar Creek, MD	104,000	185,500	25+
Amoco Oil	Wood River, IL	104,000	127,000	25+
Ashland Oil	Findlay, OH	20,400	8,000	25+
Ashland Oil	Louisville, KY	25,200	29,000	25+
Champlin Petroleum	Enid, OK	53,800	58,500	25+
Conoco, Inc.	Wrenshall, MN	23,500	25,700	5
Gulf Oil	Toledo, OH	50,300	61,800	25+
Mobil Oil	Augusta, KS	50,000	83,900	25+
Phillips Petroleum	Kansas City, KS	80,000	156,700	25+
Texaco Inc.	Lockport, IL	72,000	136,000	25+
FRS Total	-	583,200	872,100	
PAD Total	-	907,750	1,212,000	
FRS Share	-	64.2	72.0	
PAD District III				
Gulf Oil	Venice, LA	28,700	46,300	13
FRS Total	-	28,700	46,300	
PAD Total	-	1,185,214	999,180	
FRS Share	-	2.4	4.6	
PAD District IV				
Texaco Inc.	Casper, WY	21,000	35,500	25+
FRS Total	-	21,000	35,500	
PAD Total	-	60,620	61,500	
FRS Share	-	34.6	57.7	
PAD District V				
No FRS Companies				
PAD Total	-	176,750	203,100	
U.S. Totals	-	2,526,634	2,664,260	
FRS Companies	-	754,900	1,127,400	
FRS Share	-	29.9	42.3	

Note: Capacity is in barrels per calendar year.
Source: Energy Information Administration, Petroleum Supply Annual, 1984, pp. 113-115.

Table 26. Refining Statistics for FRS Companies Ranked by Total Energy Assets and Domestic Industry, 1981-1984

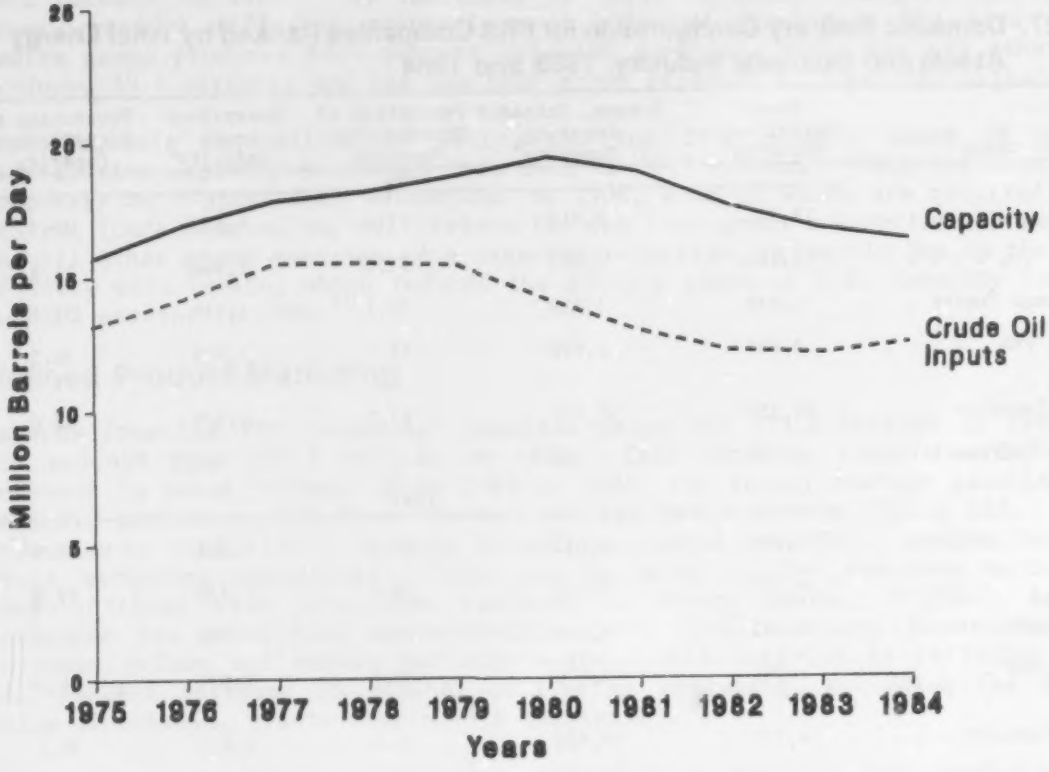
Refining Statistics	FRS Companies: All FRS	Share of U.S.	Top Four	Share of U.S.	Five Through Twelve	Share of U.S.	All Other	Share of U.S.	Domestic Industry
1981									
Refinery Output	11,281	77.2	3,897	26.7	4,359	29.8	3,025	20.7	14,614
Percentage Gasoline	46.4	80.1	42.0	25.1	49.4	33.0	47.6	22.0	44.7
Percentage Distillate	22.6	69.3	21.4	22.7	22.1	26.3	24.7	20.4	25.1
Number of Refineries	114	37.3	34	11.1	36	11.8	44	14.4	306
Refinery Capacity									
Year's Change (Net)	-525	69.9	-179	23.8	-257	34.2	-89	11.9	-751
End of Year	14,560	77.3	4,834	25.7	5,265	27.9	4,461	23.7	18,845
Utilization Rate	72.0	NM	74.1	NM	70.0	NM	68.1	NM	68.3
1982									
Refinery Output	10,627	75.9	3,387	24.2	4,103	29.3	3,137	22.4	14,005
Percentage Gasoline	48.3	79.0	44.1	23.0	53.1	33.5	46.5	22.4	46.4
Percentage Distillate	24.9	73.5	22.5	21.2	25.8	29.4	26.2	22.8	25.7
Number of Refineries	106	40.3	32	12.2	33	12.5	41	15.6	263
Refinery Capacity									
Year's Change (Net)	-920	75.0	-367	29.9	-217	17.7	-336	27.4	-1,226
End of Year	13,640	77.4	4,467	25.4	5,048	28.7	4,125	23.4	17,619
Utilization Rate	72.9	NM	68.4	NM	80.0	NM	70.7	NM	67.0
1983									
Refinery Output	10,378	76.4	3,278	24.1	3,965	26.6	3,135	23.1	13,585
Percentage Gasoline	49.0	78.5	46.3	23.4	52.5	32.1	47.3	22.9	47.7
Percentage Distillate	23.5	70.0	22.4	21.1	22.1	25.1	26.5	23.8	25.7
Number of Refineries	102	40.6	31	12.4	31	12.4	40	15.9	251
Refinery Capacity									
Year's Change (Net)	-626	74.0	-95	11.2	-467	55.2	-64	7.6	-846
End of Year	13,014	77.6	4,372	26.1	4,581	27.3	4,061	24.2	16,773
Utilization Rate	73.9	NM	69.6	NM	79.4	NM	72.2	NM	70.3
1984									
Refinery Output	10,996	77.6	3,594	25.4	4,361	30.8	3,041	21.5	14,171
Percentage Gasoline	47.0	78.4	46.7	25.5	48.2	31.9	45.5	21.0	46.5
Percentage Distillate	25.5	73.0	24.2	22.7	24.2	27.5	28.9	22.9	27.1
Number of Refineries	102	44.9	34	15.0	31	13.7	37	16.3	227
Refinery Capacity									
Year's Change (Net)	-243	49.8	122	NM	58	NM	-423	86.7	-488
End of Year	12,771	78.2	4,494	27.5	4,639	28.4	3,638	22.3	16,325
Utilization Rate	79.5	NM	78.6	NM	85.6	NM	73.4	NM	75.4

NM = Not meaningful.

Note: Refinery output and capacity data in thousand barrels per day. Domestic industry includes Puerto Rico and the Virgin Islands.

Source: Domestic industry refining capacity data are computed from data in Energy Information Administration, Petroleum Supply Annual (1981-1984). Domestic industry refinery output data are computed from the above source and supplemented by data for the Virgin Islands and Puerto Rico that were compiled for the International Energy Agency by the Petroleum Supply Division, Office of Oil and Gas, Energy Information Administration.

Figure 15. Refinery Capacity and Crude Oil Inputs for Domestic Industry, 1975-1984



Sources: • Crude Oil Inputs - Energy Information Administration, Monthly Energy Review, May 1985, DOE/EIA-0035(85/05) (Washington, D.C., August 1985) and data supplied by the Office of Oil and Gas, Energy Information Administration. • Capacity - Energy Information Administration, Petroleum Supply Annual, 1984, (June 1985).

The ability to process low-quality crudes is reflected in the heavy/sour crude capacities shown in Table 27. The FRS companies account for most of this type of capacity in the United States. However, their share of the total fell in 1984. While the FRS companies' ratio of heavy/sour capacity to distillation capacity increased slightly, the ratio for domestic industry increased more. As a result, the gap between the FRS companies and domestic industry narrowed from 6.8 percentage points in 1983 to 4.7 percentage points in 1984.

Table 27. Domestic Refinery Configuration for FRS Companies Ranked by Total Energy Assets and Domestic Industry, 1983 and 1984

Company Group	Crude Distillation Capacity[a]	Octane, Unleaded Boosting Capacity[b]	Percentage of Distillation Capacity	Heavy/Sour Crude Capacity[c]	Percentage of Distillation Capacity
			1984		
All FRS	12,771	8,815	69.0	4,693	36.7
Top Four	4,494	3,257	72.5	1,864	41.5
Five Through Twelve . .	4,639	3,530	76.1	1,510	32.6
All Other FRS	3,638	2,028	55.7	1,319	36.3
Domestic Industry . . .	16,325	10,971	67.2	5,229	32.0
FRS Share (percent) . .	78.2	80.3		89.7	
			1983[d]		
All FRS	13,014	9,013	69.3	4,671	35.9
Top Four	4,372	3,075	70.3	1,738	39.8
Five Through Twelve . .	4,581	3,464	75.6	1,520	33.2
All Other FRS	4,061	2,474	60.9	1,413	34.8
Domestic Industry . . .	16,773	10,926	65.1	4,873	29.1
FRS Share (percent) . .	77.6	82.5		95.9	

[a]Crude distillation capacity in thousand barrels per calendar day. Other capacities in thousand barrels per stream day.
[b]Includes catalytic reforming, fresh feed catalytic cracking, hydrocracking, and alkylation capacities.
[c]Includes hydrotreating and hydrorefining capacities exclusive of pretreated catalytic reformer feed, naphtha desulfurization, and naphtha olefin or aromatics saturation.
[d]Revised.

Sources: •FRS companies' crude distillation capacity: Form EIA-28. •Other capacities: Energy Information Administration, Petroleum Supply Annual and Oil and Gas Journal (March 26, 1984, and December 31, 1984).

While the five through twelve group of companies has the lowest ratio of heavy/sour capacity, they have the highest ratio of octane-enhancement capacity (76.1) among the FRS groups. This capability is reflected in the proportion of gasoline in their output slate, 48.2 percent, the highest among the FRS groups in 1984. The top four group's output slate consisted of 46.7 percent gasoline and the all other group produced 45.5 percent gasoline. In comparison, 46.5 percent of domestic industry output was gasoline in 1984 (Table 26).

The composition of gasoline output for FRS companies has been shifting to unleaded for several years. In 1984, unleaded output increased by 10.2 percent to 3,189 thousand barrels per day. The FRS companies' share of unleaded gasoline output, as a percentage of their total gasoline output, increased from 57.2 percent in 1983 to 62.2 percent in 1984. In contrast, the unleaded gasoline share was 55.3 percent of domestic industry total gasoline output in 1983 and 60.2 percent in 1984.[9] As indicated by their refinery configuration, the FRS groups produce different proportions of unleaded gasoline. The five through twelve group produced 63.4 percent unleaded gasoline, while the all other group produced 59.7 percent, and the top four group produced 62.8 percent unleaded.

With Texaco's acquisition of Getty, the top four group's share of domestic distillation capacity increased from 26.1 to 27.5 percent. This increase may be temporary as dispositions subsequent to 1984, some of which are required by the Federal Trade Commission, will reduce the top four group's distillation capacity. The all other group experienced a capacity reduction, primarily due to the merger of Getty with Texaco, which reduced the group's share of U.S. capacity from 24.2 to 22.3 percent in 1984.[10]

Refined Product Marketing

Revenue from the FRS companies' gasoline sales was $75.0 billion in 1984, down 3.5 percent from $77.7 billion in 1983. This occurred despite a 2.5-percent increase in sales volume. From 1983 to 1984, the annual average gasoline price fell 5.9 percent to $35.80 per barrel for the FRS companies (Table 24). Falling prices and, until 1984, falling demand, pressured the FRS companies to revamp their marketing operations. This can be seen in the numerous market area consolidations that have been reported in recent years. Further, many FRS companies are rebuilding or renovating their retail outlets in an attempt to increase volume and reduce per-unit costs. This activity is reflected in the 46.3-percent increase in capital outlays on marketing, excluding the purchase value of existing assets (Table 4 in Chapter 2).

Within gasoline marketing operations, streamlining gasoline distribution networks has been the primary objective for the past several years. The portion of gasoline sold through wholesale resellers has increased, while the portion of sales to retail outlets, particularly to lessee and open dealers, has decreased. For example, in 1977 the FRS companies sold 40.4 percent of their gasoline to wholesale resellers. By 1984, this percentage had increased to 47.4 percent. During the same period, the percentage of gasoline sold through their direct marketing networks fell from 51.1 percent to 46.8 percent (Table 28).

The most dramatic change in the FRS companies' gasoline marketing networks is the fall in number of outlets supplied directly. In 1977, the FRS companies supplied gasoline directly to about 179,000 outlets (Table 28). By 1984, the number of outlets directly supplied had fallen to 95,601 or by 46.6 percent. This trend was also apparent in 1983 and 1984. Most of the reduction between 1977 and 1983 involved open and lessee dealers. Between 1977 and 1983, the number of open and lessee dealers fell by 46 percent, while the number of company-operated stations fell by 18 percent. However, in 1984, company-operated outlets declined by a larger percentage, 8.3 percent, than did dealer outlets, which fell by 3.4 percent. At the same time, the total volume sold by company-operated outlets fell only 0.8 percent, while the volume sold to open and lessee dealers increased

Table 28. Changes in FRS Companies' Gasoline Distribution, Selected Years, 1977-1984

Distribution Category	1977	1982	1983	1984	Percent Change from 1977	Percent Change from 1982	Percent Change from 1983
	(millions of barrels)						
Wholesale Volume . . .	941.7	947.5	955.8	993.1	5.5	4.8	3.9
Retail Volume							
Dealer Volume . . .	977.9	667.6	671.8	705.5	-27.9	5.7	5.0
Company-Operated Volume	212.6	268.4	277.2	275.0	29.4	2.5	-0.8
Total Retail Volume	1,190.5	936.0	949.0	980.5	-17.6	4.8	3.3
Direct Volume	195.8	152.5	132.2	115.6	-41.0	-24.2	-12.5
Intersegment Volume .	1.0	5.5	6.6	5.9	490.0	7.5	-11.2
Total Volume	2,329.0	2,041.4	2,043.5	2,095.1	-10.0	2.6	2.5
	(number of outlets)						
Total Retail Outlets	178,921	102,819	99,401	95,601	-46.6	-7.0	-3.8
Company-Operated Outlets	10,400	8,211	8,507	7,801	-25.0	-5.0	-8.3

Source: Form EIA-28.

by 5.0 percent. As a result, average throughput at company-operated outlets increased by 8.2 percent and by 8.7 percent at dealer outlets. This development may be indicative of improving economics for dealers because average volume is a key factor in outlet profitability.

Gasoline marketing strategies vary among the FRS companies. The all other group relies most heavily on wholesalers and company-operated outlets. In 1984, 63.9 percent of their sales (based on value shipped) was to wholesalers, up from 62.6 percent in 1983 (Table G-53 in Appendix G), and 19.2 percent was through company-operated outlets, up from 18.0 percent in 1983. Open and lessee dealers are the least important part of the marketing strategies of these companies. Dealers accounted for less than 11 percent of their sales in 1984.

In contrast, for the five through twelve group, dealers account for the largest share of gasoline sales, 44.7 percent in 1984. Wholesale resellers accounted for 36.7 percent, while company-operated outlets accounted for about 13.8 percent. The top four group also relied upon wholesale resellers for the largest portion of their gasoline sales, 41.7 percent in 1984. For this group, dealers' share of gasoline sales increased from 38.3 percent in 1983 to 41.1 percent in 1984. Their share of sales through company-operated outlets fell significantly, from 14.0 to 11.5 percent. This may be attributable to the addition of the former Getty marketing network to Texaco's gasoline marketing network. If so, the decrease may be temporary since portions of the network were being sold in 1985.

Average marketing expenses for FRS companies increased substantially in 1984. After falling by a penny per barrel from 1982 to 1983, marketing expenses jumped by 19.2 percent in 1984 to $1.86 per barrel (Table 29). However, there are substantial variations, among both individual companies and groups (Figure 16).

Table 29. Refined Product Marketing Expenses for FRS Companies Ranked by Total Energy Assets, 1982-1984

Marketing Expenses[a]	1982	1983	1984	Percent Change from 1982	Percent Change from 1983
	(dollars per barrel)				
All FRS					
Current Dollars	1.57	1.56	1.86	18.5	19.2
Constant 1984 Dollars[b]	1.69	1.62	1.86	10.1	14.8
Top Four					
Current Dollars	2.36	2.30	3.26	38.1	41.7
Constant 1984 Dollars[b]	2.54	2.38	3.26	28.3	37.0
Five Through Twelve					
Current Dollars	1.25	1.29	1.36	8.8	5.4
Constant 1984 Dollars[b]	1.35	1.34	1.36	0.7	1.5
All Other					
Current Dollars	1.17	1.17	0.92	-21.4	-21.4
Constant 1984 Dollars[b]	1.26	1.21	0.92	-27.0	-24.0

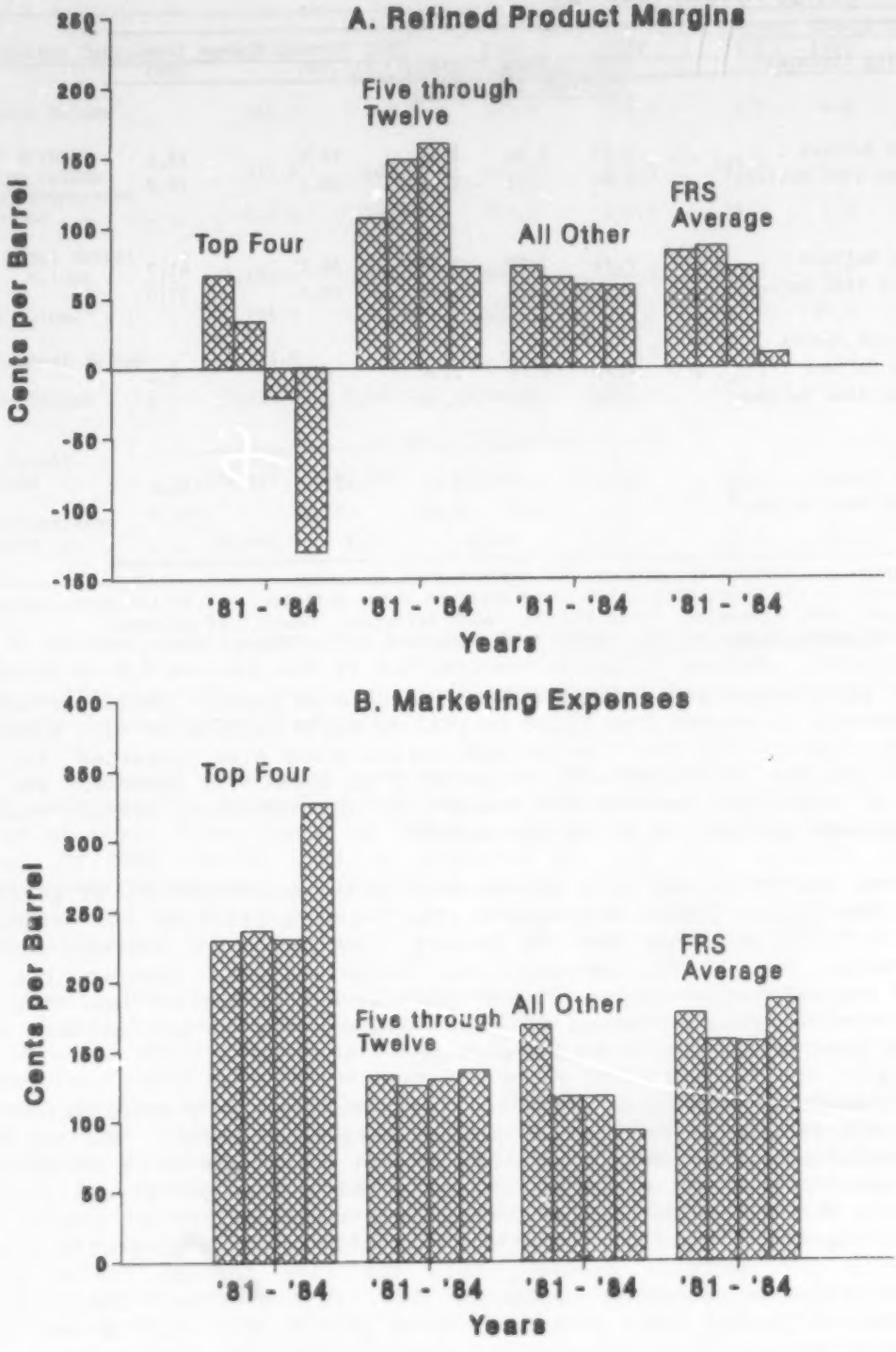
[a]Expenses are divided by total volume refined product sales.
[b]Adjusted by the Gross National Product implicit price deflator.
Sources: •FRS companies: Form EIA-28. •GNP deflator: Council of Economic Advisers, Economic Report of the President (Washington, D.C., February 1985), p. 236.

The top four group experienced the greatest increase in costs. Their per-barrel marketing expenses increased from $2.30 in 1983 to $3.26 in 1984 or 41.7 percent. The marketing expenses for the five through twelve group also increased, but the increase was a modest $0.07, from $1.29 to $1.36 in 1984. In contrast, the all other group of companies, already the lowest cost distributors, further reduced marketing expenses by $0.24 to $0.92 per barrel.

As noted above, outlet volume is a key element in the profitability of gasoline marketing. This factor likely explains a significant portion of the financial performance differences among the FRS groups. In 1984, the average monthly volume per outlet for all FRS companies was 36,000 gallons. However, the top four group's average outlet volume (26,000 gallons) was 46 percent less than the five through twelve group's average of 47,000 gallons and 38 percent less than the all other group's average of 42,000 gallons.

The overall impact of marketing expenses, input costs, and product prices is reflected in the FRS companies' refined product margin per barrel. The top four group experienced a negative margin of $1.31 in 1984, while the other two groups, which had lower per-barrel marketing expense, had higher per-barrel product margins (Figure 16). The five through twelve group's refined product margin fell 55 percent to $0.72 per barrel, while the all other group's margin fell from $0.59 to $0.58 per barrel. However, only the five through twelve group experienced a positive operating income in 1984, $155 million. The positive product margins of the all other group were outweighed by the negative impact of the differential between other refining/marketing revenues and expenses.

Figure 16. Marketing Expenses per Barrel of Product for FRS Companies, 1981-1984



Source: Form EIA-28.

Footnotes to Chapter 4

[1]For this report and for all years in it, the companies were ranked by the 1982 book value of net PP&E plus investments and advances in petroleum, coal, nuclear, and other energy lines of business combined. The companies were then grouped as follows: "top four" includes the four largest; "five through twelve" includes those ranked 5 through 12; and "all other" includes those ranked below 12. In pre-1982 editions of Performance Profiles of Major Energy Producers, a similar grouping was based on the sum of the 1978 book values of net PP&E, investments and advances, inventories, trade accounts and notes receivables, and other non-current assets in the same lines of business. The two groupings differ in that two companies moved from the five through twelve group to the all other group, while two companies moved conversely and one company in the all other group was absorbed through merger in 1982.

[2]The data for Figure 13 were taken from Standard & Poor's Compustat Services, Inc., which in turn obtains the information from companies' filings of Securities and Exchange Commission Form 10K. Companies generally do not disclose the measure of income shown in Figure 12, net income contribution, and thus a commonly used measure of profitability, the ratio of net income to stockholders' equity, is shown instead in Figure 13. The companies comprising non-FRS oil and gas producers are all companies in the Compustat data base classified in Standard Industrial Classification (SIC) industry 1311 (crude petroleum and natural gas) excluding FRS companies. The companies comprising non-FRS refiners/marketers are all companies in the data base classified in SIC industry 2911 (petroleum refining) excluding FRS companies and their Canadian affiliates, British Petroleum, Royal Dutch Shell, and Shell Trading and Transport.

[3]An indicator of the relationship of supply to anticipated demand is the ratio of stocks to consumption. In natural gas, one measure of this relationship is the ratio of working gas in underground storage to natural gas consumption. Based on weighted averages of monthly data, this ratio rose from 1.52 in 1981 to 1.69 in 1982 to 1.88 in 1983. In 1984, the ratio was reduced to 1.61 through the production cuts made in 1983. The ratio for 1981 was computed from data appearing in Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(83/12[4])(Washington, D.C., March 1984), pp. 58-59; for 1982 from Monthly Energy Review, DOE/EIA(84/12)(Washington, D.C., March 1985), pp. 62-63; and for 1983 and 1984 from Monthly Energy Review, DOE/EIA-0035(85/6)(Washington, D.C., September 1985), pp. 62-63.

[4]An after-tax measure of cash flow contribution would be the sum of net income contribution, DD&A, dry hole expense, and deferred income taxes. Since deferred taxes are not reported by line of business, the measure presented in Table 22 was utilized. See Chapter 2 and Appendix D for further discussion of the concept of cash flow.

[5]Energy Information Administration, Monthly Energy Review, (DOE/EIA-0035(85/06)(Washington, D.C., September 1985) pp. 68-69.

[6]Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(85/06), pp. 95, 105.

[7]Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(85/6), pp. 68-69.

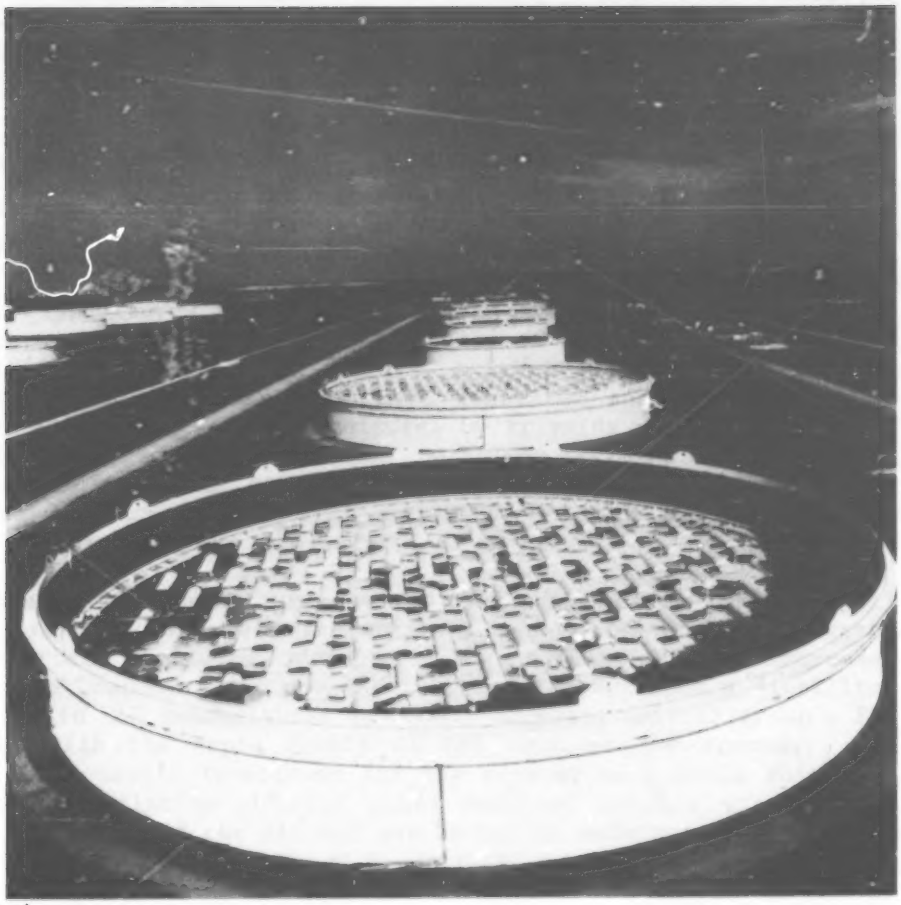
[8]Energy Information Administration, Petroleum Supply Annual 1984, Vol. 1, DOE/EIA-0340(84)/1 (Washington, D.C., June 1985), p. 111.

[9]Energy Information Administration, Petroleum Supply Annual 1983, Vol. 1, DOE/EIA-0340(83)/1 (Washington, D.C., June 1984), p. 34; and Petroleum Supply Annual 1984, Volume 1, p. 48.

[10]As discussed in Chapter 2, the Chevron-Gulf merger was not completed in 1984 and thereby did not affect the refinery data.

Chapter 5

Domestic Petroleum Resource Development



Storage Area at
Strategic Petroleum
Reserves

5. Domestic Petroleum Resource Development

Despite some decline in domestic crude oil prices, overall profitability of domestic oil and gas production rose $1.1 billion, or 8.5 percent, for the FRS companies in 1984. Their domestic production of oil and gas rose 1.4 and 7.9 percent, respectively, increasing overall revenues from domestic upstream operations by 3.5 percent.

The FRS companies' domestic exploration and development (E&D) expenditures also rose, by 6 percent excluding investment values associated with major acquisitions. Well completions rose even more as costs of drilling and equipping continued to decline from peak levels established in 1982. Apparent costs of finding new reserves fell for the second year in a row. Reserve additions, excluding those gained through acquisition, nearly matched the FRS companies' production for the first time since at least 1974 (the first year of FRS data collection).

Nonetheless, oil and gas markets remain highly uncertain. Domestic crude oil prices are tied to world oil markets which are unsettled due to weak aggregate demand and the overhang of large volumes of shut-in production capacity, particularly in the Middle East. Problems persist in natural gas markets as well. Following 2 years of substantial decline, production recovered somewhat in 1984, but shut-in production capacity within the United States still exists. Gas prices are subject to downward pressure due to falling oil prices, widespread capability to switch between oil and gas among industrial users and electric utilities, and increased competition from Canadian gas following major changes in Canadian energy policy in 1984.

Each of these trends has had some effect on petroleum exploration and development activities of the FRS companies, as well as the oil and gas industry as a whole.

Expenditures on Exploration and Development

Total domestic E&D expenditures by FRS companies (excluding expenditures for proved acreage which, in 1984, were largely composed of merger purchase values) rose 6 percent in 1984 to $27.4 billion dollars, a level surpassed only in 1981 and 1982. The FRS companies appeared to have generated additional funds to finance the increase in domestic E&D expenditures by trimming overhead expenses. General and administrative expenses in the petroleum segment were down 10 percent. Capital expenditures in other areas, notably domestic refining and marketing, were down 10 percent, excluding mergers. Foreign E&D expenditures were down 7 percent, again excluding the effects of mergers.

The increase in domestic E&D expenditures by the FRS companies in 1984 was well above the industry, as a whole, which registered a modest 1.4-percent increase (Table 30). Indeed, the industry increase was entirely due to increased expenditures by the FRS companies, as non-FRS companies experienced a $1-billion (or 7-percent) decline in E&D expenditures in 1984. However, neither group's E&D expenditures kept up with the rapid growth of the rest of the economy. For example, gross private domestic investment for the economy as a whole rose 35.2 percent in 1984, while inflation-adjusted gross national product grew by 6.8 percent (Table 30). Weakness in the oil and gas sector is underscored when it is recognized that during 1983 and 1984 the U.S. economy experienced the strongest economic recovery since the Korean War.[1] However, as noted below, differences in

the real rate of activity for 1984 may not be as great as the financial trends depict. Such is not likely to be true for 1985. Even though the rate of overall economic expansion has slowed it is still positive. In contrast, exploration and development expenditures and the rate of well rig activities and well completions are all significantly down.[2]

Table 30. Domestic Exploration and Development Expenditures Compared to Various Measures of Economic Activity, 1983-1984

Expenditures and Economic Activity	1983	1984	Percent Change
	(billion dollars)		
Exploration and Development Expenditures, FRS Companies	27.1	48.1	77.6
Exploration and Development Expenditures Excluding Expenditures for Proved Acreage Acquisition, FRS Companies	25.8	27.4	6.2
Exploration and Development Expenditures, Domestic Industry	40.9	41.5	1.4
Gross National Product	3,304.8	3,662.8	10.8
Gross National Product (1984 Dollars)	3,443.6	3,662.8	6.8
Gross Private Domestic Investment	471.6	637.8	35.2

Sources: •FRS companies: Form EIA-28. •Industry exploration and development expenditures: Independent Petroleum Association of America, United States Petroleum Statistics, 1985, Final (Washington, D.C., 1985). •Gross national product and gross private domestic investment: Council of Economic Advisors, Economic Report to the President (Washington, D.C., February 1985). All data taken from this latter source, unless otherwise indicated, are in current dollars. Constant dollar amounts, when indicated, were computed using the implicit GNP price deflator.

At a more disaggregated level, one observes that aside from developed acreage, the bulk of the increase in domestic E&D expenditures was for drilling and equipping wells. Drilling and equipping expenditures (including net wells in progress) were up 18.9 percent for exploration wells and 15.6 percent for development wells. The FRS companies, taking advantage of lower drilling costs (down 14.2 percent in 1984[3]) and a large inventory of drilling prospects built up during the 1979 to 1982 exploration boom, appear to have pursued a strategy in 1984 of quickly building reserves. Longer horizon investments, notably expenditures for unproved acreage and for geological and geophysical outlays, were lower (down 4.6 percent and 6.2 percent, respectively).

Drilling Activity

Increased expenditures for drilling and equipping wells, together with lower per-well drilling costs, produced a significant increase in the number of wells completed by the FRS companies in 1984. The total number of completions increased 27.4 percent to 11,086, the largest number of wells drilled in any year by the FRS companies (Table 31). Total footage drilled also showed a sharp increase, up 18.6 percent. Exploration well completions rose a respectable 22.2 percent in 1984, with a total of 2,101 completions (significantly below the record 2,563 achieved in 1981), while exploration footage increased 19.3 percent.

By comparison, development completions increased 28.7 percent (to a new record of 8,985 wells) while development footage increased a lesser 15.5 percent (Figure 17).

Table 31. Measures of Drilling and Exploratory Activity for FRS Companies and Domestic Industry, 1983-1984

Drilling and Exploratory Activity	1983	1984	Percent Change
Exploratory and Development Wells Completed			
FRS Companies	8,701	11,086	27.4
Domestic Industry	74,380	82,870	11.4
Footage of Completed Wells (thousand feet)			
FRS Companies	55,825	65,096	18.6
Domestic Industry	313,230	362,770	15.8
Average Number of Rotary Rigs in Use	2,232	2,428	8.8
Average Number of Seismic Crews	473	494	4.4

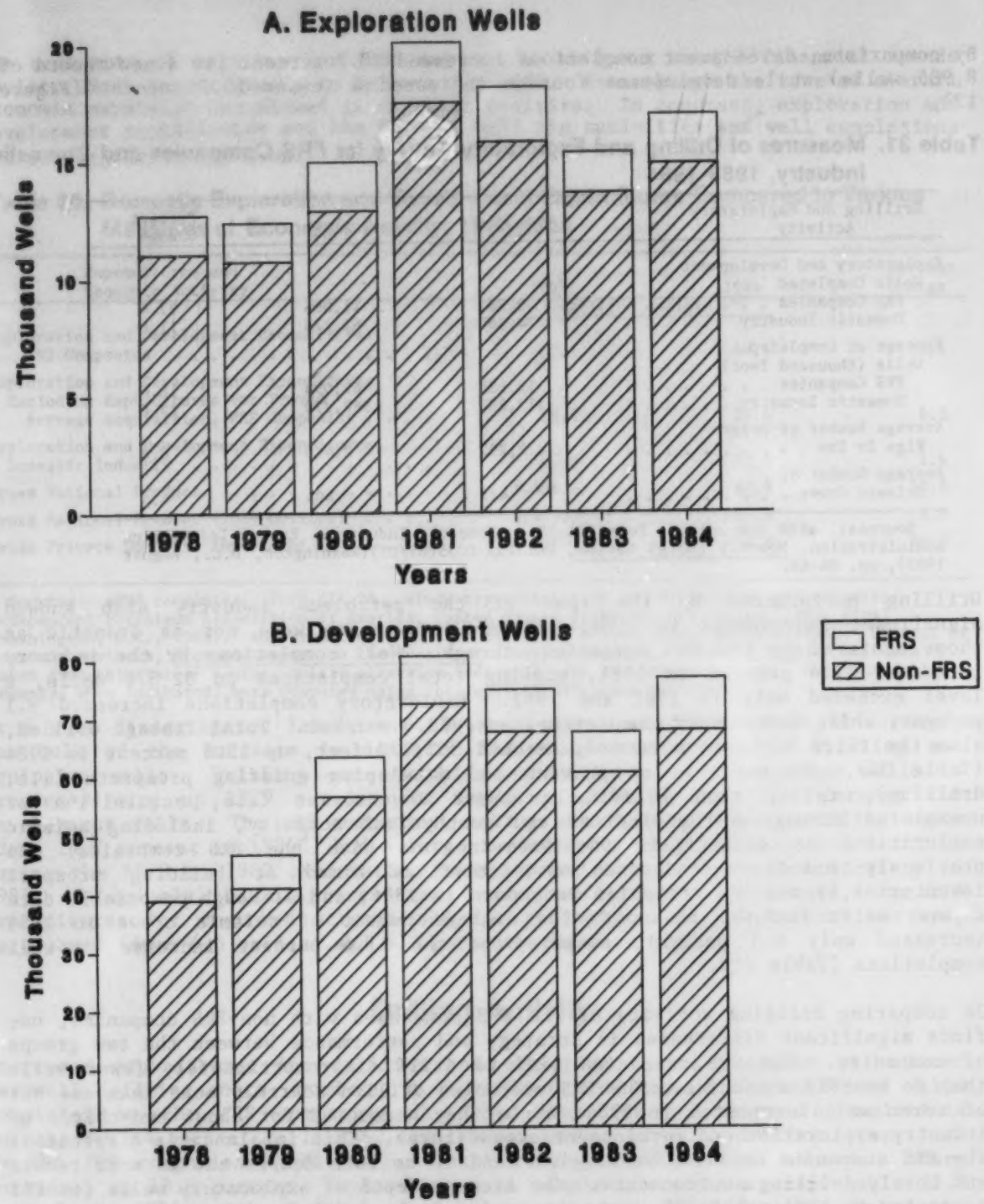
Sources: •FRS companies: Form EIA-28. •Domestic Industry: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(85/05)(Washington, D.C., August 1985), pp. 64-65.

Drilling performance by the rest of the petroleum industry also showed significant improvement in 1984. These improvements were not as dramatic as those achieved by the FRS companies, though. Well completions by the industry increased 11.4 percent in 1984, pushing total completions to 82,870 wells, a level exceeded only in 1981 and 1982. Exploratory completions increased 9.1 percent, while development completions rose 12.0 percent. Total footage drilled, also the third highest on record, reached 362,770 feet, up 15.8 percent in 1984 (Table 31). An emphasis on proving and developing existing prospects (i.e, drilling), rather than building prospect inventories (i.e, acquisition of unexplored acreage and geological and geophysical activity, including seismic exploration) is evident in the industry, as with the FRS companies. As previously noted, expenditures on activities aimed at building prospect inventories by the FRS companies were down in 1984, and although comparable data do not exist for the industry, the average number of seismic crews in 1984 increased only 4.4 percent, compared to the 11.4 percent increase in well completions (Table 31).

In comparing drilling activity of the FRS companies with non-FRS companies, one finds significant differences in strategy and performance between the two groups of companies. The FRS companies tend to drill disproportionately fewer wells than do non-FRS companies. The FRS companies drilled scarcely more than one out of seven wells completed in 1984, while they accounted for about two-thirds of industry exploration and development expenditures. This imbalance is a result of the FRS companies drilling wells that tend to be both deeper and in more remote and costly drilling environments. The average depth of exploratory wells for FRS companies in 1984 was 9,000 feet, compared to only 4,800 feet for the rest of the industry, and the average depth of development wells was 5,100 feet versus 4,000 feet (Table 32). In addition, the FRS companies drilled over one-half of all

READEX FICHE best copy available

Figure 17. Domestic Exploration and Development Well Completions for FRS and Non-FRS Companies, 1978-1984



Sources: • FRS companies - Form EIA-28. • Non-FRS companies - Industry total less FRS companies; industry totals provided by Energy Information Administration, Office of Oil and Gas, and correspond to totals published in Energy Information Administration, Monthly Energy Review, May 1985, DOE/EIA-0035(85/05) (Washington, D.C., August 1985), p. 65.

offshore wells, where drilling costs are higher per foot. As a result, the average cost per well for FRS companies, historically, has been about 3 times greater than for non-FRS companies. The results of these different strategies are evident in reserve additions per well: the FRS companies added more than 6 times the reserves per well as did non-FRS companies in 1984 (299,400 barrels of crude oil equivalent for FRS companies versus 48,800 barrels for non-FRS companies).[4]

Table 32. Comparison of FRS and Non-FRS Companies' Drilling Activities, 1984

Drilling Measures	FRS	Non-FRS
Average Depth of Exploratory Wells (thousand feet)	9.0	4.8
Average Depth of Development Wells (thousand feet)	5.1	4.0
Percent of All Offshore Wells Completed (percent)	51.3	48.7
Percent of All Onshore Wells Completed (percent)	12.6	87.4
Average Reserve Addition per Well Completed (thousand barrels)[a]	299.4	48.8

[a]Excludes net purchase of minerals in place.

Sources: oFRS companies: Form EIA-28. oNon-FRS data: calculated from estimated well completion data compiled by Energy Information Administration, Office of Oil and Gas, which correspond to estimated well completion data reported in Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(85/05)(Washington, D.C., August 1985) and from industry reserve data from Energy Information Administration, U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves, DOE/EIA-0216(84)(Washington, D.C., September 1985).

The two groups of companies also appear to have responded differently to the recent instability in crude oil prices. In the period 1979 to 1981, when oil prices were rising rapidly, both exploratory and development drilling by non-FRS companies grew at a more rapid rate than for FRS companies. Similarly, from 1981 to 1984, when oil prices were falling, non-FRS companies cut drilling more drastically than did FRS companies (Figure 17). One reason for this difference is that the rapid price escalation of 1979 to 1981 attracted enormous amounts of new capital to the petroleum industry. Much of this capital was raised through limited partnerships. These funds financed drilling for many smaller companies, while the FRS companies were more reliant on internally generated funds. With the fall in oil prices, entry of new capital into the industry has diminished considerably, adding to the cash flow crunch affecting drilling by smaller companies.

The increase in drilling activity in 1984 was not uniform across onshore and offshore areas. Although the FRS companies' exploratory drilling increased at about the same rate for onshore and offshore areas (22.0 percent versus 22.6 percent, respectively), onshore development drilling surged 30.7 percent compared to a 1.9-percent decline offshore. The decline in offshore development drilling is consistent with an overall trend toward development of lower-cost prospects, a trend which is directly attributable to the recent decline in crude oil prices. The average cost of a development well for FRS companies in 1984 was $447,000 onshore, compared to $3.5 million offshore, and, as discussed in a later section, the cost of adding a barrel of oil and gas reserves offshore is noticeably

greater compared to onshore. The strong performance in offshore exploration drilling reflects the substantial inventory of exploration prospects that have been built up recently with the greatly accelerated Federal Outer Continental Shelf (OCS) oil and gas leasing program. Between 1982 and 1984 offshore lease acreage held by the FRS companies more than tripled (see section on Lease Acreage).

Oil Versus Gas Well Drilling

The increased drilling activity was also not evenly distributed across oil and natural gas. Continuing a trend that began in 1979, an increased emphasis was placed on oil drilling relative to gas drilling. For the FRS companies, the rate of increase in development oil well completions (up 34.5 percent) was nearly 5 times greater than the increase in natural gas completions (up 7.1 percent) (Table 33). Expenditures on development oil completions increased 17.8 percent, compared to a decline of 6.3 percent for natural gas. The difference was not quite so dramatic for exploratory drilling but the same trend is apparent. Exploratory oil completions by FRS companies increased 20.6 percent, compared to a 15.8-percent increase in natural gas completions. Expenditures on exploratory oil completions rose 11.8 percent, while natural gas expenditures fell 18.3 percent.

Table 33. Oil and Gas Well Completions by FRS Companies and Domestic Industry, 1983-1984

Completed Wells	1983	1984	Percent Change
Exploration			
Oil Wells			
FRS	452	545	20.6
Domestic Industry	2,080	2,290	10.1
Gas Wells			
FRS	295	342	15.8
Domestic Industry	1,630	1,500	-8.0
Development			
Oil Wells			
FRS	5,324	7,160	34.5
Domestic Industry	34,650	39,720	14.6
Gas Wells			
FRS	1,056	1,131	7.1
Domestic Industry	12,740	14,650	15.0

Sources: •FRS companies: Form EIA-28. •Domestic industry: Energy Information Administration, Office of Oil and Gas; disaggregated industry well completions correspond to the total well completion estimates published in Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(85/05) (Washington, D.C., August 1985).

Combining exploration and development wells, the ratio of natural gas well completions to oil well completions dropped to the lowest level since 1974, the first year of FRS drilling statistics. Only 1 out of 6 successful wells completed by FRS companies in 1984 was a natural gas well. For the industry as a

whole the ratio was about 1 out of 4, but this level is also the lowest in recent history (Figure 18). Some of the year-to-year variation in natural gas versus oil well completions are a result of changes in exploratory opportunities and the large degree of uncertainty, especially with exploratory wells, as to whether a find will be predominately natural gas or oil. However, the sharp increase in emphasis in natural gas drilling evident in the period 1974 to 1978, and the equally sharp decrease from 1979 to 1984, are at least in part a response to some of the critical events of the past decade that have shaped the conduct and performance of the petroleum industry.

From 1974 to 1978, despite price controls affecting both oil and gas, the wellhead price of natural gas rose more rapidly than the wellhead price of oil. Natural gas prices more than tripled during this period, while oil prices increased only 30 percent, clearly favoring a greater emphasis on gas drilling.[5]

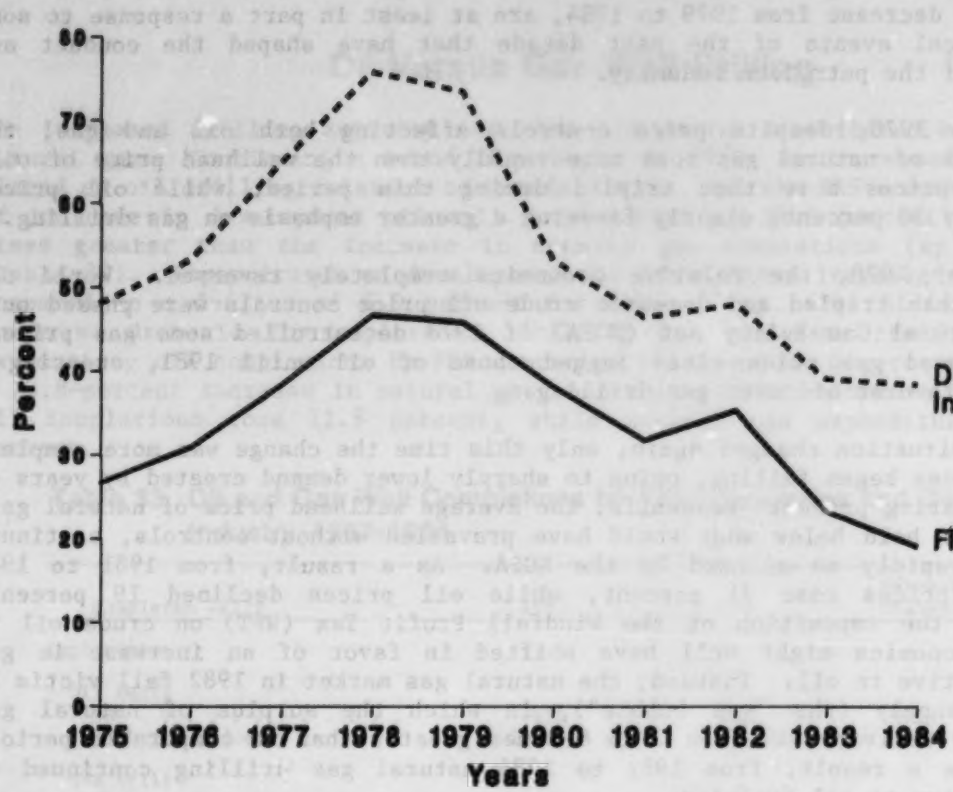
However, after 1978, the relative economics completely reversed. World oil prices more than tripled and domestic crude oil price controls were phased out. While the Natural Gas Policy Act (NGPA) of 1978 decontrolled some gas prices, overall wellhead gas price rises lagged those of oil until 1981, creating a climate that favored oil over gas drilling.

In 1981 the situation changed again, only this time the change was more complex. Crude oil prices began falling, owing to sharply lower demand created by years of rapidly escalating prices. Meanwhile, the average wellhead price of natural gas, which had been held below what would have prevailed without controls, continued to rise as rapidly as allowed by the NGPA. As a result, from 1981 to 1984 natural gas prices rose 31 percent, while oil prices declined 19 percent. Coupled with the imposition of the Windfall Profit Tax (WPT) on crude oil in 1981, the economics might well have shifted in favor of an increase in gas drilling relative to oil. Instead, the natural gas market in 1982 fell victim to serious oversupply (the "gas bubble"), in which the surplus of natural gas available for delivery was from 2 to 8 times greater than in comparable periods in 1981.[6] As a result, from 1981 to 1984 natural gas drilling continued to decline relative to oil drilling.

Lease Acreage

In 1984, the FRS companies had a total of 211 million acres under lease domestically, a decrease of 6.9 percent from 1983. As this was the second consecutive year of decrease, it appears that the FRS companies are shedding marginal acreage to reduce costs in the face of falling oil prices. All of the acreage reduction occurred onshore. Onshore undeveloped acreage (which accounts for three-fourths of the total) fell 11.9 percent, and onshore developed acreage dropped 1.3 percent (Table 34). Partially offsetting these declines were healthy gains in the FRS companies' offshore acreage holdings: offshore undeveloped acreage rose an impressive 43.1 percent (following a 47.2-percent increase in 1983) and offshore developed acreage grew by 21.5 percent. The huge increase in offshore undeveloped acreage occurred even as the FRS companies expenditures for unproved acreage offshore dropped 8 percent (from $4.4 billion in 1983 to $4.1 billion in 1984) (Table 35).

Figure 18. Gas Wells Completed as a Percent of Oil Wells Completed for FRS Companies and Domestic Industry, 1975-1984



Sources: • FRS Companies - Form EIA-28. • Domestic Industry - Energy Information Administration, Monthly Energy Review, May 1985, DOE/EIA-0035(85/05) (Washington, D.C., August 1985), p. 65.

Table 34. Domestic Net Petroleum Acreage Under Lease for FRS Companies and Domestic Industry, 1984 and Percent Change from 1983

Petroleum Acreage	Undeveloped Acreage		Developed Acreage		Total Acreage	
	Millions of Acres	Percent Change from 1983	Millions of Acres	Percent Change from 1983	Millions of Acres	Percent Change from 1983
FRS Companies						
Onshore	159.0	-11.9	29.7	-1.3	188.7	-10.4
Offshore	18.2	43.1	4.4	21.5	22.6	38.3
Total	177.2	-8.3	34.1	1.2	211.3	-6.9
Domestic Industry	NA	NA	NA	NA	587.6	-0.8

NA = Not available.
Note: Percent change calculated from unrounded data.
Sources: •FRS companies: Form EIA-28. oDomestic industry: Independent Petroleum Association of America, The Oil Producing Industry in Your State 1985 (Washington, D.C., 1985).

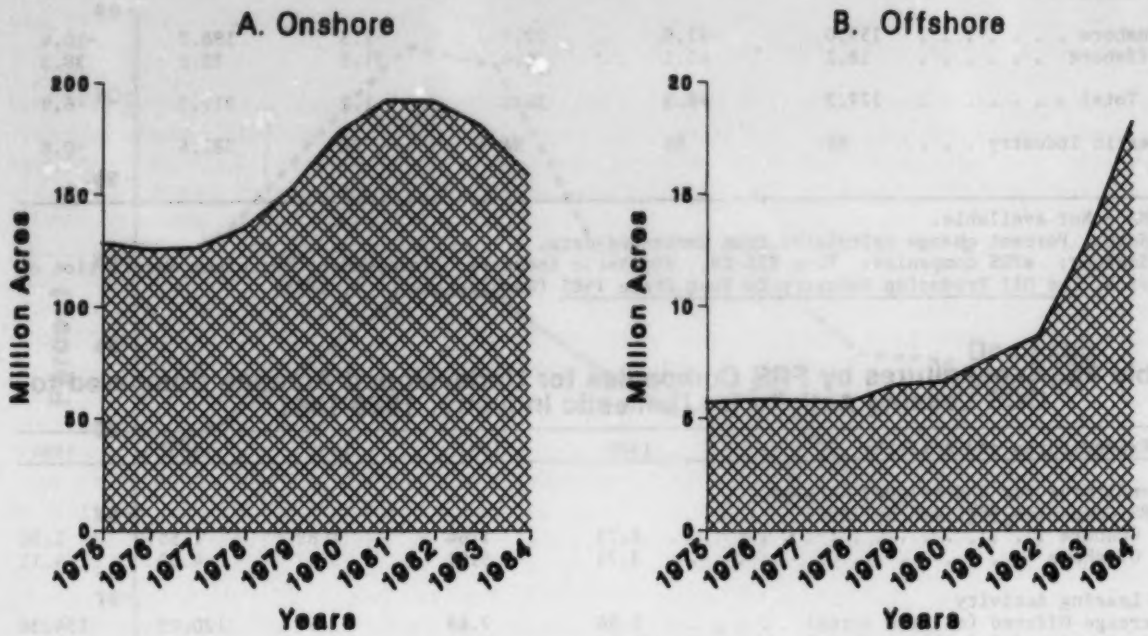
Table 35. Expenditures by FRS Companies for Undeveloped Acreage Compared to OCS Leasing Activity for Domestic Industry, 1980-1984

Expenditures and Activity	1980	1981	1982	1983	1984
Expenditures for Undeveloped Acreage, FRS Companies (billion dollars)					
Onshore	1.73	1.64	1.89	1.55	1.56
Offshore	3.75	5.91	3.17	4.39	4.11
OCS Leasing Activity					
Acreage Offered (million acres)	2.56	7.68	7.64	120.05	154.38
Acreage Awarded (million acres)	1.13	2.26	1.89	6.59	7.49
Lease Bonuses (billion dollars)	4.20	6.60	3.99	5.75	4.04

Sources: •FRS companies: Form EIA-28. •OCS leasing activity: U.S. Department of the Interior, Minerals Management Service, Federal Offshore Statistics (Washington, D.C., September 1984). Leasing activity figures for 1984 were obtained directly from the Minerals Management Service.

While not always so dramatic as in recent years, the comparatively greater interest by the FRS companies in undeveloped offshore acreage has been a trend since FRS data were first collected. From 1974 to 1984 undeveloped offshore acreage nearly quadrupled, while undeveloped onshore acreage grew by only 20 percent and has been declining since 1981 (Figure 19). During the same period undeveloped offshore acreage, as a share of all undeveloped acreage, rose from 3 percent to 10 percent. The sharp increase in offshore undeveloped acreage since 1980 has occurred largely as a result of a greatly expanded Federal OCS leasing program. The amount of acreage offered in OCS lease sales increased 60-fold from 1980 and the amount of acreage leased by industry in these sales increased nearly 7-fold during the same period (Table 35). Although total spending on lease bonuses for offshore acreage has been sustained at high levels in recent years, the amount spent per acre has fallen dramatically. In 1980, the average OCS lease bonus was $3,707 per acre compared to $539 in 1984.

Figure 19. Domestic Onshore and Offshore Undeveloped Acreage Holdings for FRS Companies, 1975-1984



Source: FRS companies - Form EIA-28.

Reserves, Reserve Additions, and Production

In general, the crude oil and natural gas liquids reserves picture improved for both FRS companies and industry in 1984, while the natural gas reserves picture worsened. For the FRS companies, crude oil and natural gas liquids (NGL) reserves increased 2.4 percent, while natural gas reserves declined 0.7 percent. Industry wide, crude oil and NGL reserves increased 1.3 percent, but natural gas reserves declined 1.4 percent (Table 36). All of the U.S. reserve gain reflects an increase in crude oil reserves. This was the first increase in crude oil reserves since 1970, when the discovery of the Prudhoe Bay field boosted crude oil reserves to a high of 39 billion barrels. With the increase in 1984, total domestic crude oil reserves stood at 28.4 billion barrels--still 27 percent below the 1970 level. The increase in the FRS companies' crude oil and NGL reserves was the first for them since 1974, when FRS reserve data were first available (Figure 20). In 1984 total domestic natural gas reserves dropped to 197.5 trillion cubic feet (tcf), compared to 290.8 tcf in 1970. The decline in natural gas reserves was the 12th such decline in the past 14 years (the two increases occurred in 1980 and 1981).

Table 36. Comparison of FRS and Industry Reserves and Production, 1984

Reserves, Production, and Reserve Additions	FRS		Industry	
	Amount 1984	Percent Change From 1983	Amount 1984	Percent Change From 1983
Crude Oil and NGL End-of-Year Reserves (Billion Barrels)	21.3	2.4	36.1	1.3
Dry Natural Gas End-of-Year Reserves (Trillion Cubic Feet)	107.3	-0.7	197.5	-1.4
Crude Oil and NGL Production (Billion Barrels)	2.1	1.4	3.8	1.8
Dry Natural Gas Production (Trillion Cubic Feet)	7.9	7.9	17.2	8.9
Crude Oil, NGL, and Dry Natural Gas Reserve Additions (Billion Barrels Crude Oil Equivalent)[a]	3.3	16.0	6.8	-0.8

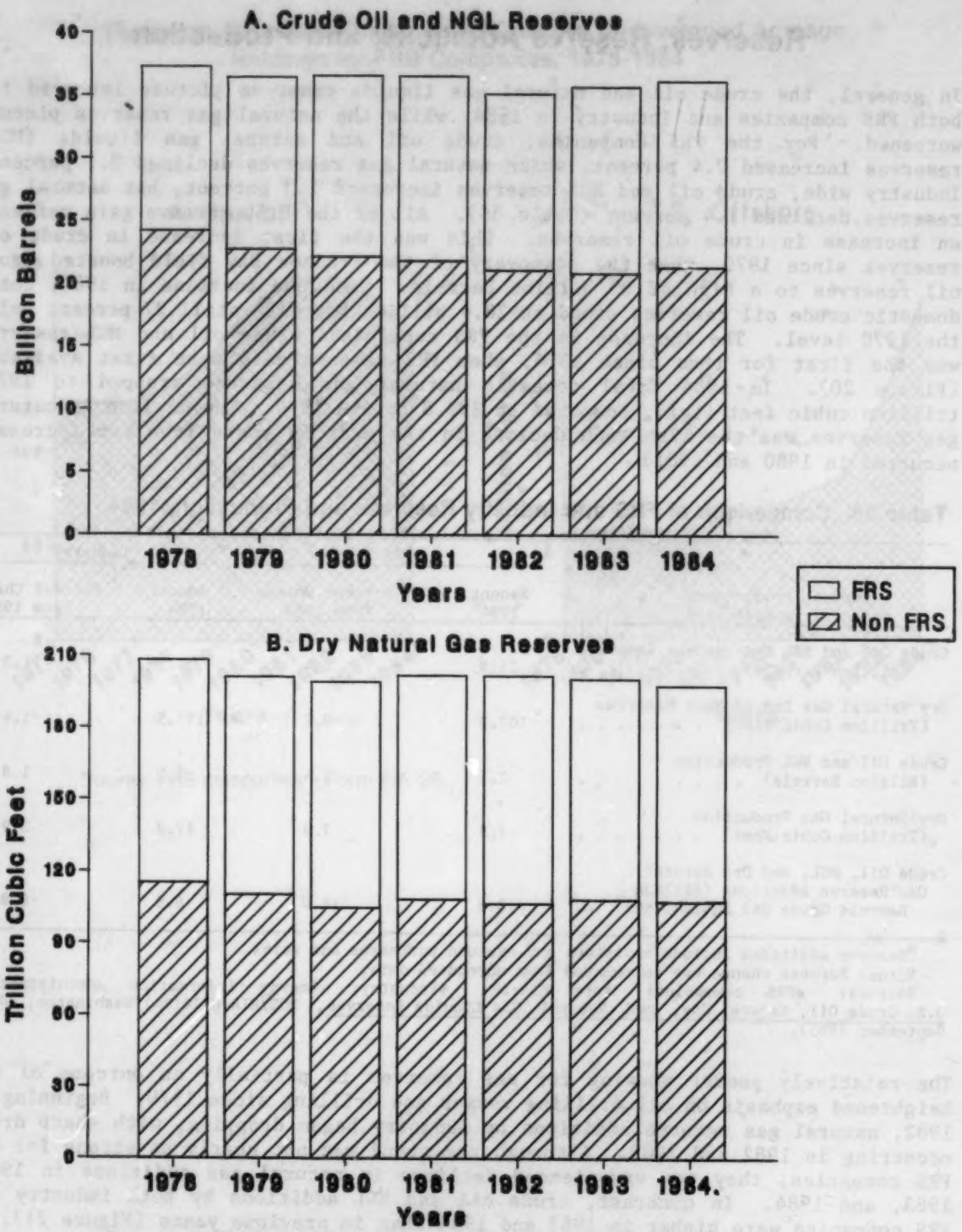
[a]Reserve additions include revisions and exclude purchases and sales.

Note: Percent change was calculated from unrounded data.

Sources: •FRS companies: Form EIA-28. •Industry: Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216(84)(Washington, D.C., September 1985).

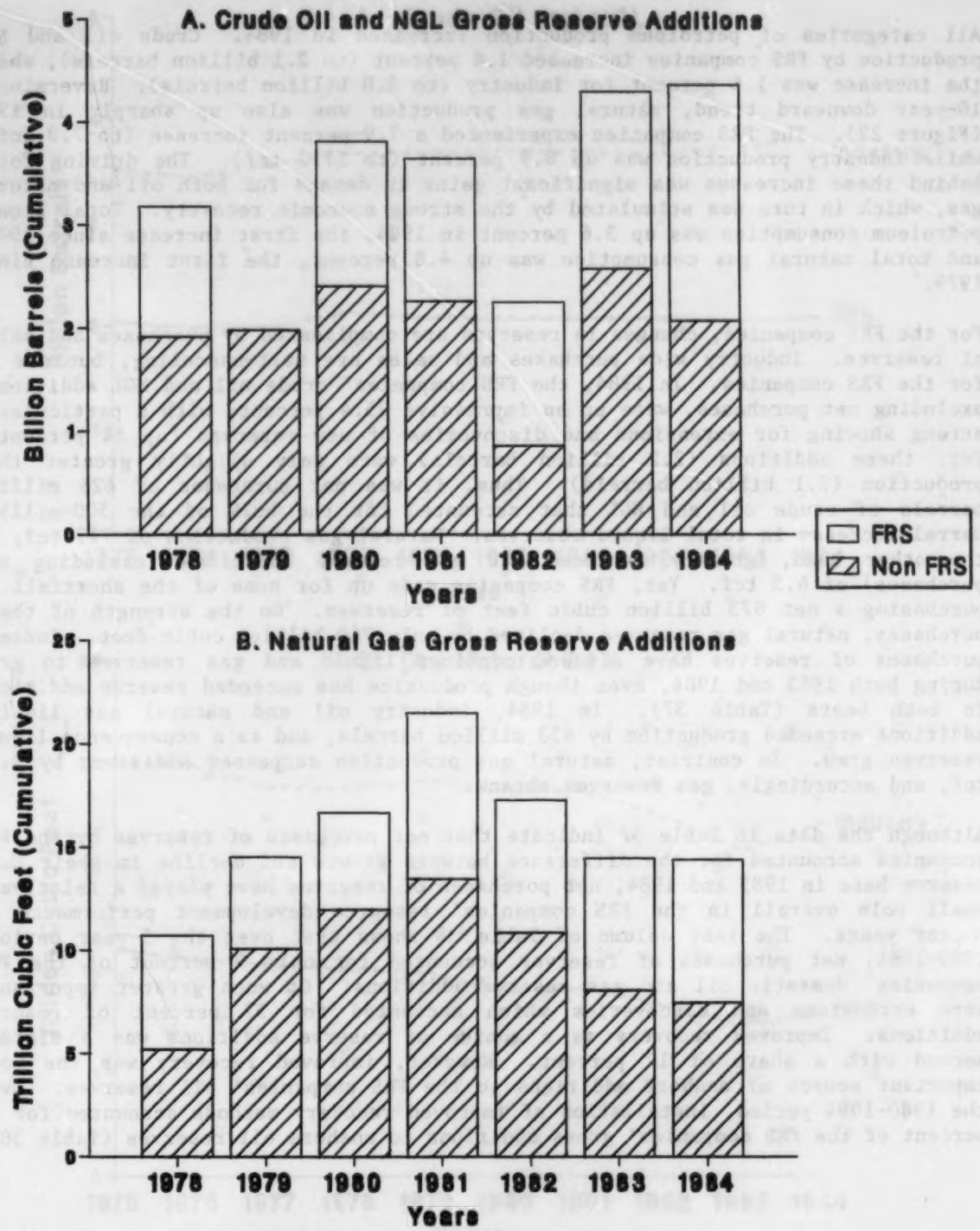
The relatively poorer showing for gas reserves is partially an outcome of the heightened emphasis on oil drilling versus gas drilling since 1979. Beginning in 1982, natural gas reserve additions by industry began dropping, with sharp drops occurring in 1982 and 1983. Although the trend was not nearly as strong for the FRS companies, they too experienced declines in natural gas additions in 1982, 1983, and 1984. In contrast, crude oil and NGL additions by both industry and FRS companies were higher in 1983 and 1984 than in previous years (Figure 21).

Figure 20. Domestic Crude Oil, NGL, and Dry Natural Gas Reserves for FRS and Non-FRS Companies, 1978-1984



Source: • FRS Companies - Form EIA-28. • Non-FRS Companies - Industry Totals less FRS companies; industry totals computed from Energy Information Administration, U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves, DOE/EIA-0216(84) (Washington, D.C. September 1985).

Figure 21. Domestic Crude Oil, NGL, and Dry Natural Gas Gross Reserve Additions for FRS and Non-FRS Companies, 1978-1984



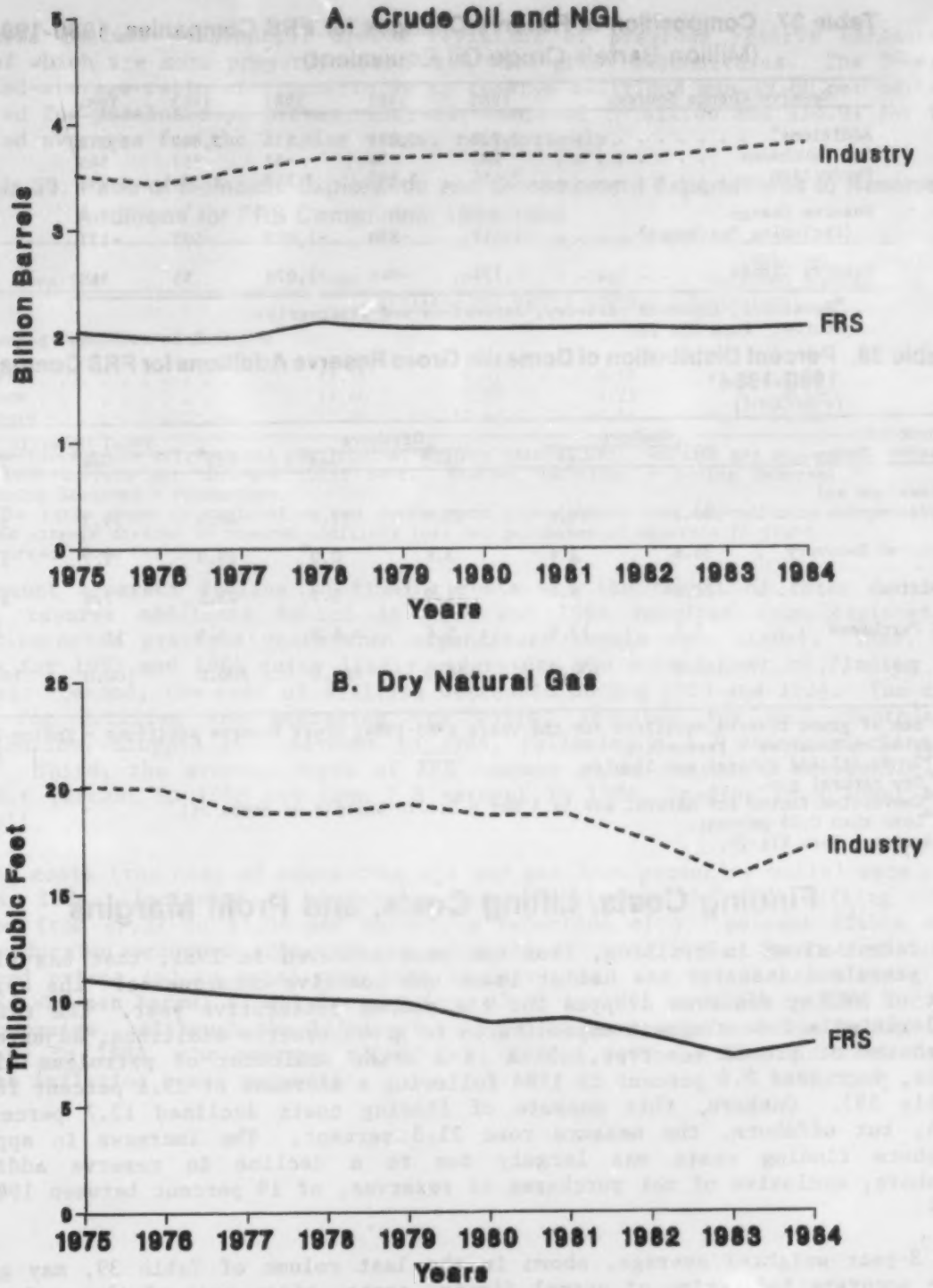
Sources: • FRS Companies - Form EIA-28. • Non-FRS Companies - Industry Totals less FRS companies; industry totals computed from Energy Information Administration, U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves, DOE/EIA-0216(84) (Washington, D.C. September 1985).

All categories of petroleum production increased in 1984. Crude oil and NGL production by FRS companies increased 1.4 percent (to 2.1 billion barrels), while the increase was 1.6 percent for industry (to 3.8 billion barrels). Reversing a 10-year downward trend, natural gas production was also up sharply in 1984 (Figure 22). The FRS companies experienced a 7.9-percent increase (to 7.9 tcf), while industry production was up 8.9 percent (to 17.2 tcf). The driving force behind these increases was significant gains in demand for both oil and natural gas, which in turn was stimulated by the strong economic recovery. Total liquid petroleum consumption was up 3.6 percent in 1984, the first increase since 1978, and total natural gas consumption was up 4.8 percent, the first increase since 1979.

For the FRS companies, changes in reserves are complicated by purchases and sales of reserves. Industry wide purchases and sales are self-canceling, but not so for the FRS companies. In 1984, the FRS companies' crude oil and NGL additions, excluding net purchases, were up an impressive 25.4 percent, with a particularly strong showing for extensions and discoveries of new reserves (up 54 percent). Yet, these additions (2.2 billion barrels) were only slightly greater than production (2.1 billion barrels). Thus, it was net purchases of 426 million barrels of crude oil and NGL that accounted for the bulk of the 500-million barrel increase in total liquid reserves. Natural gas production of 7.9 tcf, on the other hand, greatly exceeded FRS gas reserve additions (excluding net purchases) of 6.5 tcf. Yet, FRS companies made up for some of the shortfall by purchasing a net 673 billion cubic feet of reserves. On the strength of these purchases, natural gas reserves declined by only 749 billion cubic feet. Indeed, purchases of reserves have allowed combined liquid and gas reserves to grow during both 1983 and 1984, even though production has exceeded reserve additions in both years (Table 37). In 1984, industry oil and natural gas liquids additions exceeded production by 453 million barrels, and as a consequence liquid reserves grew. In contrast, natural gas production surpassed additions by 2.78 tcf, and accordingly, gas reserves shrank.

Although the data in Table 37 indicate that net purchases of reserves by the FRS companies accounted for the difference between growth and decline in their U.S. reserve base in 1983 and 1984, net purchases of reserves have played a relatively small role overall in the FRS companies' resource development performance in recent years. The last column of Table 38 shows that over the 5-year period, 1980-1984, net purchases of reserves accounted for only 9 percent of the FRS companies' domestic oil and gas reserve additions. Of much greater importance were extensions and discoveries which accounted for 57 percent of reserve additions. Improved recovery as a source of reserve additions was a distant second with a share of 17 percent. However, improved recovery was the most important source of onshore additions to the FRS companies' oil reserves. Over the 1980-1984 period, installation of improved recovery methods accounted for 36 percent of the FRS companies' gross additions to onshore oil reserves (Table 38).

Figure 22. Domestic Crude Oil, NGL, and Dry Natural Gas Production for FRS and Domestic Industry, 1975-1984



Sources: • FRS Companies - Form EIA-28. • Industry - Energy Information Administration, U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves, DOE/EIA-0216(84) (Washington, D.C. September 1985).

Table 37. Composition of Reserve Changes for FRS Companies, 1980-1984
(Million Barrels Crude Oil Equivalent)

Reserve Change Sources	1980	1981	1982	1983	1984
Additions[a]	2,238	2,815	2,535	2,862	3,319
Net Purchases	282	34	-52	557	545
Production	3,656	3,695	3,553	3,364	3,497
Reserve Change (Excluding Purchases)	-1,419	-880	-1,018	-502	-177
Reserve Change	-1,137	-846	-1,070	55	368

[a]Revisions, improved recovery, extensions and discoveries.
Source: Form EIA-28.

Table 38. Percent Distribution of Domestic Gross Reserve Additions for FRS Companies, 1980-1984[a]
(Percent)

Source of Reserve Change	Onshore		Offshore		Total Domestic		
	Oil[b]	Gas[c]	Oil[b]	Gas[c]	Oil[b]	Gas[c]	Total[d]
Extensions and Discoveries	30.2	74.6	78.9	87.9	40.2	79.3	56.8
Improved Recovery	35.6	2.6	3.6	0.0[e]	29.0	1.7	17.4
Revisions	26.5	8.8	11.9	5.2	23.5	7.6	16.7
Net Purchases	7.7	13.9	5.6	6.8	7.3	11.4	9.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[a]Sum of gross reserve additions for the years 1980-1984; Gross Reserve Additions = Ending Reserves Beginning Reserves + Production.
[b]Crude oil and natural gas liquids.
[c]Dry natural gas.
[d]Conversion factor for natural gas is 1 Mcf = 0.1772 barrels of crude oil.
[e]Less than 0.05 percent.
Source: Form EIA-28.

Finding Costs, Lifting Costs, and Profit Margins

The recent slump in drilling, from the peak achieved in 1981, that has plagued the petroleum industry has had at least one positive consequence: the apparent cost of adding reserves dropped for the second consecutive year. The ratio of exploration and development expenditures to gross reserve additions, adjusted for purchases of proved reserves, which is a crude indicator of petroleum finding costs, decreased 8.4 percent in 1984 following a decrease of 29.1 percent in 1983 (Table 39). Onshore, this measure of finding costs declined 13.7 percent in 1984, but offshore, the measure rose 21.3 percent. The increase in apparent offshore finding costs was largely due to a decline in reserve additions offshore, exclusive of net purchases of reserves, of 19 percent between 1983 and 1984.

The 3-year weighted average, shown in the last column of Table 39, may give a more accurate indication of actual finding costs, since most of the exploration expenditures associated with current-year reserve additions occurred in previous years when expenditure levels were higher. In addition, current-year reserve

estimates include substantial upward revisions of previous reserve estimates, most of which are more properly associated with prior expenditures. The 3-year, weighted-average ratio of expenditures to reserve additions was $9.80 per barrel, adjusted for purchases of proven reserves, compared to $11.06 and $10.91 for the weighted averages for the 2 prior years, respectively.

Table 39. Ratio of Domestic Exploration and Development Expenditures to Reserve Additions[a] for FRS Companies, 1982-1984

Location	1982	1983	1984	1982-1984 Weighted Average
	(dollars per barrel crude oil equivalent)			
Excluding Purchases of Reserves[b]				
All FRS	12.71	9.01	8.25	9.80
Onshore	12.44	7.22	6.23	8.16
Offshore	13.20	13.65	16.56	14.30

[a]Includes crude oil, natural gas liquids, and dry natural gas. Natural gas converted at .1772 barrels per thousand cubic feet. Reserve additions = Ending Reserves - Beginning Reserves + Production.

The ratio shown is exploration and development expenditures less expenditures for proved acreage divided by reserve additions less net purchases of minerals in place.

Source: Form EIA-28.

The recent apparent decline in finding costs was the result of three factors. First, reserve additions booked in 1983 and 1984 resulted from exploration expenditures in previous years when expenditure levels were higher. Thus, the ratios for 1983 and 1984 quite likely understate the actual cost of finding oil and gas. Second, the cost of drilling decreased during 1983 and 1984. The cost index for drilling and equipping new wells, adjusted for well depth and distribution, dropped 14.2 percent in 1984, following a 3.7 percent-decline in 1983.[8] Third, the average depth of FRS company wells decreased substantially, down 8.6 percent in 1983 and down 7.8 percent in 1984, leading to a lower cost per well.

Lifting costs (the cost of extracting oil and gas from producing wells) were also down in 1984. Inclusive of production taxes (including the WPT) lifting costs dropped from $7.37 to $7.04 per barrel, a reduction of 4.5 percent (Table 40). This reduction occurred primarily as a result of lower WPT. Because of lower wellhead prices and an escalating base against which the tax is calculated, the average WPT per barrel of oil dropped from $3.35 in 1983 to $2.74 in 1984 for the FRS companies. Although the lifting cost, net of taxes, increased slightly (2.6 percent) in 1984, the average net-of-tax lifting cost declined in real terms because inflation was 4 percent.

Table 40. Petroleum Lifting Costs for FRS Companies, 1978-1984

Lifting Costs	1978	1979	1980	1981	1982	1983	1984
	(dollars per barrel)[a]						
Cost with Production Taxes							
Onshore	2.07	2.55	5.14	9.52	8.72	7.86	7.64
Offshore	1.22	1.49	3.04	6.70	5.66	5.81	5.22
Total	1.88	2.31	4.66	8.86	7.97	7.37	7.04
Cost without Production Taxes							
Total	1.54	1.87	2.56	3.09	3.84	4.24	4.35

[a]Calculated by dividing total lifting costs by total crude oil, natural gas liquid, and natural gas production, on a crude oil equivalent basis.
Source: Form EIA-28.

The apparent improvements in drilling and production efficiency should yield corresponding improvements in the average profitability of petroleum exploration and development. The average before-tax profit per barrel of oil discovered can be defined as the average gross revenue (i.e, the wellhead price), minus finding and lifting costs. Finding costs pose a measurement problem because it is impossible to exactly match expenditures with resultant reserve additions. There are significant lags between lease acquisition, geological and geophysical efforts, exploratory drilling, and development drilling. Moreover, if an after-tax measure is to be obtained, then the tax treatment of each expenditure component must be considered. In an attempt to correct for timing-induced measurement bias and to account for tax effects, a simple calculation routine was developed that provided estimates of before- and after-tax finding costs. The routine incorporates an expenditure allocation table that specifies the lag between the occurrence of a category of expenditure and the associated reserve additions (Table 41). For example, 10 percent of the expenditures incurred for acquisition of unproved acreage 4 years ago are assumed to contribute to current reserve additions. Similarly, 20 percent of lease expenditures occurring 3 years ago, 40 percent of those occurring 2 years ago, and 30 percent of those occurring 1 year ago are also assumed to contribute to current reserve additions. These lag assumptions appear to be typical for domestic exploration and production.[9]

Table 41. Fraction of Current and Previous Years' Exploration and Development Expenditures Attributed to Current Reserve Additions

Expenditure Category	Year[a]				
	t-4	t-3	t-2	t-1	t
Unproved Acreage	0.1	0.2	0.4	0.3	
Drilling and Equipping				0.4	0.6
Geological and Geophysical	0.2	0.3	0.4	0.1	
Other, Including Overhead			0.3	0.3	0.4

[a]The letter "t" represents the current year.

Assumptions were also required for the tax treatment of various categories of expenditures. It was assumed that 80 percent of unexplored acreage and geological and geophysical expenditures were expensed and 20 percent recaptured through cost depletion; exploratory and development dry holes and overhead were 100 percent expensed; 100 percent of development equipment and facility

expenditures were depreciated using the 5-year accelerated cost recovery system (ACRS); and 70 percent of non-dry hole drilling and equipping expenditures were assumed intangible, with 80 percent of this amount expensed and the remainder depreciated over 3 years. Since capital recovery through depreciation and cost depletion occur in the future, and some of the expenditures occur prior to the addition of reserves, all financial values were discounted to present value using an 8-percent real (inflation-adjusted) discount rate. This rate is equal to the average rate of return on equity (minus inflation) in the petroleum industry in 1983[10] and is 1 percentage point greater than the yield (net of inflation) on Aaa corporate bonds in that year.[11]

The analysis reveals that even when expenditure lags are accounted for, the finding costs for the FRS companies appear to have declined significantly in 1983 and 1984, with a total decline of nearly 40 percent over the 2-year period (Table 42). Averaging 60 percent of the before-tax values, after-tax finding costs declined proportionately. The decline in finding costs appears to have led to a considerable improvement in the average per-barrel profit margin, even as wellhead prices declined (Table 42). The after-tax profit margin had dipped to a negative $0.32 per barrel in 1982, owing to high finding costs and high windfall profit tax payments. By 1984 the margin increased to $2.80 per barrel, despite the significant drop in wellhead crude oil prices from 1982 to 1984.

Table 42. Before and After Tax Revenue, Costs, and Profit Margins for FRS Companies, 1982-1984 (1984 dollars per barrel)[a]

Revenues and Costs	1982	1983	1984
Revenue[b]			
Before Tax	24.14	22.88	22.36
After Tax	13.04	12.36	12.07
Finding Costs[c]			
Before Tax	14.75	10.65	9.13
After Tax	8.72	6.31	5.47
Lifting Costs[d]			
Before Tax	8.59	7.65	7.04
After Tax	4.64	4.13	3.80
Profit Margin[e]			
Before Tax	0.80	4.58	6.19
After Tax	-0.32	1.92	2.80

[a]All dollar values converted to 1984 dollars using the implicit GNP price deflator.
[b]Value of reserve additions at current-year prices. Oil price is average FRS company production sales price of crude oil and NGL. Gas price is price of new gas (NGPA categories 102, 103, 108, and 109) from Energy Information Administration, Natural Gas Monthly, DOE/EIA-0130(85/08)(Washington, D.C., October 1985), p. 12.
[c]Based on Table 41.
[d]Includes production taxes.
[e]Revenue less finding and lifting costs.
Source: Form EIA-28.

Footnotes to Chapter 5

[1]Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(85/05)(Washington, D.C., August 1985), p. 29.

[2]Oil and Gas Journal (February 25, 1985), p. 46.

[3]Independent Petroleum Association of America, Report of the Cost Study Committee, (Washington, D.C., May 30, 1985). Change reported is for direct operator cost adjusted for well depth and distribution.

[4]Reserve additions in this chapter, unless otherwise noted, are defined as end-of-year reserves, minus beginning-of-year reserves, plus production, minus net purchases of minerals in place.

[5]Increases in oil and natural gas wellhead prices were computed from data in Energy Information Administration, Annual Energy Review 1984, DOE/EIA-0384(84)(Washington, D.C., April 1985), p. 25.

[6]Based on data in Energy Information Administration, Natural Gas Monthly, DOE/EIA-0130(85/07) (Washington, D.C., September 1985), p. 14.

[7]Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(85/05)(Washington, D.C., August 1985), p. 7.

[8]Independent Petroleum Association of America, Report of the Cost Study Committee.

[9]Two sources providing support for these lag assumptions are A. T. Guernsey, Economics of Domestic Crude Oil and Natural Gas Exploration and Development 1959-1976 (Shell Oil Co., 1977), and Glenn A. Welsch and Edward B. Deakin, Measuring and Reporting the Replacement Cost of Oil and Gas Reserves (American Petroleum Institute, Washington, D.C., 1977).

[10]Independent Petroleum Association of America, The Oil and Gas Producing Industry in Your State 1985-1986, (Washington, D.C., September 1985) p. 118.

[11]Council of Economic Advisors, Economic Report of the President 1985 (Washington, D.C., January 1985), p. 298.

Chapter 6

Foreign Petroleum Developments

Liquid Petroleum Tanker

6. Foreign Petroleum Developments

World oil markets reflected mixed development patterns in 1984. Overall demand for oil rose for the first time since 1979. However, the rise was small and total crude oil production was still 15 percent below peak levels. Non-OPEC crude production, led by gains in relatively new producing areas, reached record levels in 1984. Production by OPEC oil producers fell for the fifth consecutive year and was lower than at any time since 1967. Most of the decline was borne by Saudi Arabia.

Official prices for crude oil were relatively stable following price adjustments announced in early 1983. However, spot market prices showed frequent signs of weakness. Nonetheless, the cost of oil and oil products in most countries outside the United States tended to rise due to the rapid appreciation of the dollar relative to other currencies.

These and other developments presented opportunities and problems for FRS companies with multinational operations. The opportunities centered on improved access to equity crude production. Exploration and development efforts of prior years yielded increased output and profits from upstream operations in 1984. Profit opportunities from further expansion of these operations spurred continued high levels of new upstream investment.

The problems centered principally on poor profits and poor profit prospects from foreign refining and marketing operations, particularly in Europe. Narrowed margins between crude and product prices, combined with low overall refinery utilization, caused profits from this line of activity to fall sharply. Though capacity utilization rates rose in 1984, this was wholly due to reductions in installed capacity. Foreign refined product output was at its lowest level since FRS data collection began. Further, by 1984, FRS companies' foreign refining capacity had fallen by 22 percent from the 1980 level. With the exception of Texaco, most FRS companies have been curtailing foreign refining and marketing operations. Through the sale of assets to Texaco in 1984, Chevron withdrew from most refining and marketing operations in Europe. This followed Gulf's withdrawal in 1983 when it sold most of its European refining and marketing assets to the Kuwait Petroleum Company.

Income and Investment in Foreign Petroleum

Income

Over the period 1974 through 1980, about half of the FRS companies' foreign net income was generated from refining and marketing and half from upstream activities. Since 1981, upstream net income has been relatively stable, while downstream income has fallen and remains depressed. In 1984, upstream activities generated over 95 percent of foreign petroleum income.

Foreign upstream net income increased by 2.9 percent in 1984 to $7.5 billion. However, the increase was solely due to the top four group's results, which increased by 11.2 percent to $5.2 billion (Table 43). The more favorable results for the top four companies in large part reflect their increased oil production abroad, which rose 18 percent between 1983 and 1984. This increase accounted

for nearly 90 percent of the total growth in production of all FRS companies. About 40 percent of the production gain came from European sources, particularly the North Sea, and nearly 30 percent was accounted for by Other Eastern Hemisphere sources, particularly Indonesia and Malaysia.

Table 43. Foreign Petroleum Contribution to Net Income for FRS Companies Ranked by Total Energy Assets, 1981-1984

Contribution to Net Income	1981	1982	1983	1984	Percent Change 1983-1984
	(billion dollars)				
Foreign Petroleum					
Top Four	6.1	4.2	5.5	5.4	-2.2
Five Through Twelve	1.8	1.8	1.7	1.7	-3.5
All Other	1.8	0.7	0.9	0.7	-20.3
All FRS	9.6	6.7	8.2	7.8	-4.5
Foreign Petroleum Segments					
Production					
Top Four	4.5	3.6	4.7	5.2	11.2
Five Through Twelve	1.9	1.8	1.8	1.6	-8.3
All Other	1.7	0.7	0.8	0.6	-20.9
All FRS	8.0	6.1	7.2	7.5	2.9
Refining/Marketing					
Top Four	1.5	0.8	1.2	0.5	-58.1
Five Through Twelve	-0.1	0.0[a]	-0.0[a]	0.1	NM
All Other	0.2	0.0[a]	0.1	0.1	-11.8
All FRS	1.6	0.8	1.3	0.7	-45.7
International Marine					
Top Four	0.1	-0.2	-0.4	-0.3	NM
Five Through Twelve	-0.0[a]	-0.0[a]	-0.1	-0.1	NM
All Other	-0.1	-0.0[a]	-0.0[a]	-0.0[a]	NM
All FRS	-0.1	-0.3	-0.5	-0.4	NM

[a]Less than $50 million.
NM = Not meaningful.
Note: Sum of components may not equal total due to eliminations and nontraceables or independent rounding. Percent changes based on unrounded data.
Source: Form EIA-28.

The FRS companies' foreign refining and marketing net income fell by 45.7 percent to $0.7 billion in 1984 (Table 43). These results reflect the adverse effects of an increasingly strong dollar in 1984. One overall index of the dollar's value showed an increase of 17 percent in 1984.[2] Although dollar-denominated crude oil prices fell slightly in 1984, local currency prices of crude oil and refined products sold in foreign locales increased, restraining overall demand. Weak product demand and intense competition spurred by excess refining capacity caused refining margins to virtually disappear. As a result of these adverse conditions, FRS companies are sharply scaling down foreign refining/marketing operations. Foreign refinery output of the FRS companies fell by more than 300,000 barrels per day, or 6 percent, between 1983 and 1984. Net investment in place was reduced 10 percent in 1984 as $16 billion of net investment in place yielded only $0.7 billion in income. Only the five through twelve group experienced an increase in refining and marketing net income in 1984. Income for this group equaled $108 million in 1984 compared to a loss of $9 million in 1983.

Results from the FRS companies' international marine operations were even poorer. Losses were reported for the fourth consecutive year. Total losses for the FRS group were $394 million in 1984, with the top four companies accounting for $330 million of the total (Table 43). Lower overall demand and increased crude oil production and imports from regions such as Canada, Mexico, and the North Sea, which are relatively close to major consuming centers, have reduced both the number and length of marine voyages. Combined with a general oversupply of tankers, these developments have reduced tanker rates to unprofitable levels. As a result, many FRS companies are reducing their tanker fleets and writing down asset values.

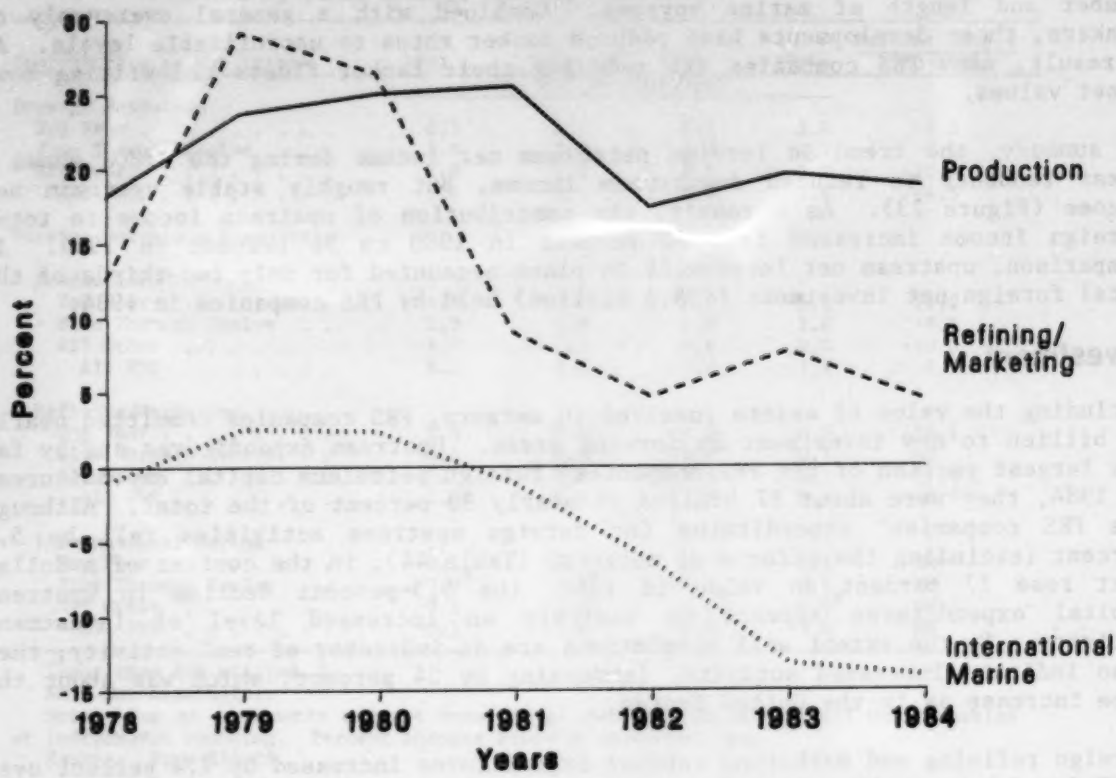
In summary, the trend in foreign petroleum net income during the 1980s shows a clear tendency to reduced downstream income, but roughly stable upstream net income (Figure 23). As a result, the contribution of upstream income to total foreign income increased from 62 percent in 1980 to 96 percent in 1984. In comparison, upstream net investment in place accounted for only two-thirds of the total foreign net investment ($58.4 billion) held by FRS companies in 1984.

Investment

Excluding the value of assets involved in mergers, FRS companies committed nearly $9 billion to new investment in foreign areas. Upstream expenditures are by far the largest portion of the FRS companies' foreign petroleum capital expenditures. In 1984, they were about $7 billion or nearly 80 percent of the total. Although the FRS companies' expenditures for foreign upstream activities fell by 5.5 percent (excluding the effects of mergers) (Table 44), in the context of a dollar that rose 17 percent in value in 1984, the 5.5-percent decline in upstream capital expenditures appears to indicate an increased level of investment activity. To the extent well completions are an indicator of real activity, they also indicate increased activity, increasing by 24 percent, which was about the same increase as in the United States.

Foreign refining and marketing capital expenditures increased by 7.4 percent over 1983 levels (excluding the effects of mergers), but their level was quite low relative to earlier years (Figure 24). As in 1983, most of these expenditures were devoted to refinery upgrading. A portion of these expenditures is due to the Saudi refinery projects of Mobil and Shell. While FRS companies continue to upgrade those foreign refineries which they still operate, they have substantially reduced foreign refinery capacity in recent years (discussed in detail in a subsequent section of this chapter). The book value of net PP&E in foreign refining and marketing declined by 9.7 percent in 1984 alone. Shrinkage of marine operations was more severe. While the international marine segment saw an increase in expenditures to $74 million in 1984, reflecting some restructuring and modernization of tanker fleets, net PP&E in this segment declined by 21 percent In 1984 alone.

Figure 23. Profit Rates in Foreign Petroleum Segments for FRS Companies, 1978-1984.



[a]Profit Rates Measured as Contribution to Net Income/Net Investment in Place.

Source: Form EIA-28.

Table 44. Additions to PP&E in Foreign Petroleum for FRS Companies Ranked by Total Energy Assets, 1983-1984

Additions to PP&E	1983	1984	Adjusted[a] 1984	Percent Change	Adjusted[a] Percent Change
	(billion dollars)				
Foreign Petroleum					
Top Four	4.3	12.9	4.8	202.3	11.6
Five through Twelve	2.6	2.3	2.3	-10.3	-10.3
All Other	2.3	1.8	1.8	-22.1	-22.1
All FRS	9.2	17.0	8.9	85.1	-2.8
Foreign Petroleum Segments					
Production					
Top Four	2.9	10.1	3.1	252.5	9.0
Five through Twelve	2.3	2.1	2.1	-7.0	-7.0
All Other	2.2	1.7	1.7	-23.7	-23.7
All FRS	7.4	14.0	7.0	88.2	-5.5
Refining/Marketing					
Top Four	1.4	2.5	1.6	86.7	15.9
Five through Twelve	0.3	0.2	0.2	-34.6	-34.6
All Other	0.1	0.1	0.1	43.9	43.9
All FRS	1.7	2.8	1.9	62.8	7.4
International Marine					
Top Four	0.0[b]	0.2	0.1	547.2	64.8
Five through Twelve	0.0[b]	0.0	0.0[b]	13.1	13.1
All Other	1.0[b]	0.0[b]	0.0[b]	-4.6	-4.6
All FRS	0.0[b]	0.2	0.1	402.0	49.0

[a]Adjusted to exclude purchase value of existing assets associated with the mergers of Chevron with Gulf, Texaco with Getty Oil, and Mobil with Superior Oil.

[b]Less than $50 million.

Note: Sum of components may not equal total due to independent rounding. Percent change was calculated from unrounded data.

Source: Form EIA-28.

Figure 24. Additions to Net Investment in Place in Foreign Petroleum for FRS Companies, 1978-1984[a]

[a] Excludes merger purchase values for 1982 and 1984.

Source: Form EIA-28.

Operating Results

Production and Resource Development

The FRS companies increased their foreign crude and NGL production by 9.4 percent in 1984, while total foreign industry production increased by only 3.7 percent (Table 45). The FRS companies' production increased in all regions, but increases were particularly evident in the Other Eastern Hemisphere region, Middle East, and OECD Europe (Table 45 and Figure 25). The Other Eastern Hemisphere's production increased 22.7 percent to 197 million barrels, and Middle East production increased by 19.2 percent to 107 million barrels. While OECD Europe's increase was a lesser 11.2 percent, this region remains the largest production source for FRS companies. Production of 441 million barrels in OECD Europe, primarily in the North Sea, accounted for 32.9 percent of FRS companies' foreign production and nearly 40 percent of production growth in 1984. Foreign industry production declined in the Middle East by 1.5 percent. This was primarily due to Saudi efforts to maintain the official OPEC price levels by reducing their output.

Foreign direct crude access is a more comprehensive measure of crude oil availability than is net ownership crude oil production. The former includes net ownership production, purchases from unconsolidated affiliates, and production access under special arrangements with foreign governments (termed foreign access). Unconsolidated affiliates have constituted a crucial conduit through which the FRS companies acquire foreign oil, particularly in the Middle East. In 1978, for example, the FRS companies obtained 68 percent of their foreign direct access crude oil and NGL from unconsolidated affiliates. By 1984, however, unconsolidated affiliates supplied only 26 percent of the FRS companies' foreign direct access oil. This decline is primarily attributable to declining production in Saudi Arabia and consequent reduction in Aramco loadings.

The FRS companies' foreign direct access crude has been falling since 1978 (Figure 26), primarily due to the decline in purchases from unconsolidated affiliates. In 1984 alone, purchases from unconsolidated affiliates fell by 30.2 percent from the prior year to 460 million barrels. In contrast, net ownership interest production has increased in every year since 1981. In 1984, net ownership production equaled 1.3 billion barrels, up 10 percent from 1983. Net ownership production now accounts for about three-fourths of all foreign crude access.

The growth to prominence of the North Sea as a source of FRS companies' oil production abroad, from 6 percent in 1977 to 33 percent in 1984, reflects exploration and development efforts directed toward this area. Europe has consistently accounted for over 40 percent of the FRS companies' foreign exploration and development expenditures over the 1977-1984 period (Figure 27). In 1984, exploration and development expenditures (excluding mergers) directed toward Europe rose slightly, by 0.4 percent, while exploration and development expenditures (excluding mergers) directed toward other areas fell (Table 45). However, the foreign well drilling statistics of the FRS companies suggest that their exploration and development efforts increased in 1984 despite an apparent decline in expenditures.

Table 45. Foreign Petroleum Exploration, Development, Reserves, and Production Statistics by Geographical Area for FRS Companies, 1984 and Percent Change from 1983

Foreign Petroleum Activities	Total	Canada	OECD Europe	Mideast	Africa	Other E. Hemisphere	Other W. Hemisphere
			(million barrels)				
Oil Production[a]							
FRS Companies	1,339	192	441	107	275	197	126
Percent Change	9.4	3.3	11.2	19.2	3.2	22.7	1.9
Foreign Industry[b]	12,011	649	1,407	4,369	1,870	1,261	2,455
Percent Change	3.7	-0.2	9.6	-1.5	8.3	11.4	4.3
			(wells completed)				
Wells Completed[c]							
FRS Companies	2,036	1,227	239	36	102	311	118
Percent Change	23.8	34.6	19.5	56.5	-11.3	13.1	0.0
Foreign Industry	16,718	9,562	1,002	396	502	1,775	3,481
Percent Change	18.3	38.0	14.3	-18.7	-9.7	13.7	-6.7
			(million dollars)				
Exploration & Development Expenditures of FRS Companies							
As Reported	17,278	5,379	5,466	467	3,391	2,031	543
Percent Change	61.6	229.6	28.3	-3.6	103.9	-0.9	-10.3
Adjusted[d]	10,000	1,607	4,277	463	1,391	1,730	532
Percent Change	-6.5	-1.5	0.4	-4.4	-16.4	-15.5	-12.2
			(percent)				
1984 Distribution of Expenditures by FRS Group							
Top Four	100.0	38.6	30.4	19.7[e]		10.0	1.3
Five through Twelve	100.0	19.8	23.5	35.1[e]		11.5	10.0
All Other	100.0	8.0	48.8	19.0[e]		20.9	3.3
All FRS	100.0	31.1	31.6	22.3[e]		11.8	3.1
All FRS, Adjusted[d]	100.0	16.1	42.8	18.5[e]		17.3	5.3
			(million barrels)				
Oil Reserve Interest[f]							
FRS Companies	14,630	2,419	4,306	1,499	3,522	1,945	939
Percent Change	-0.9	10.0	-5.9	-26.3	15.2	-4.9	9.8

[a]Crude oil plus natural gas liquids. Includes ownership interest production and foreign access production.

[b]Foreign Industry levels defined as total activity outside of the United States except the People's Republic of China and the Soviet Bloc. Yugoslavia is excluded from Foreign Industry due to nonavailability of data.

[c]For FRS companies, wells shown are preliminary estimates of net wells completed.

[d]Excludes merger purchase values.

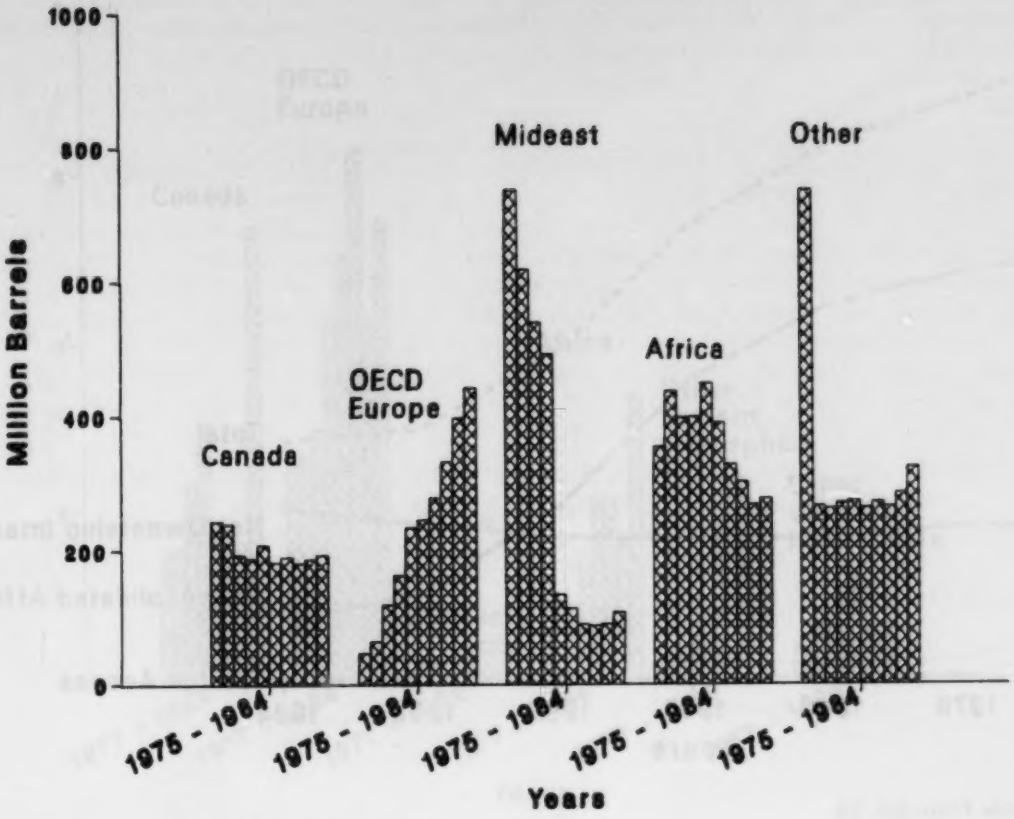
[e]Africa and Mideast regions combined to avoid disclosure.

[f]The components of total foreign crude oil and natural gas liquids reserve interest are net ownership interest reserves (89.8 percent) and "Other Access" reserves (10.2 percent). Other access reserves include proportional interest in investee reserves and foreign access reserves.

Note: Sum of components may not equal total due to independent rounding.

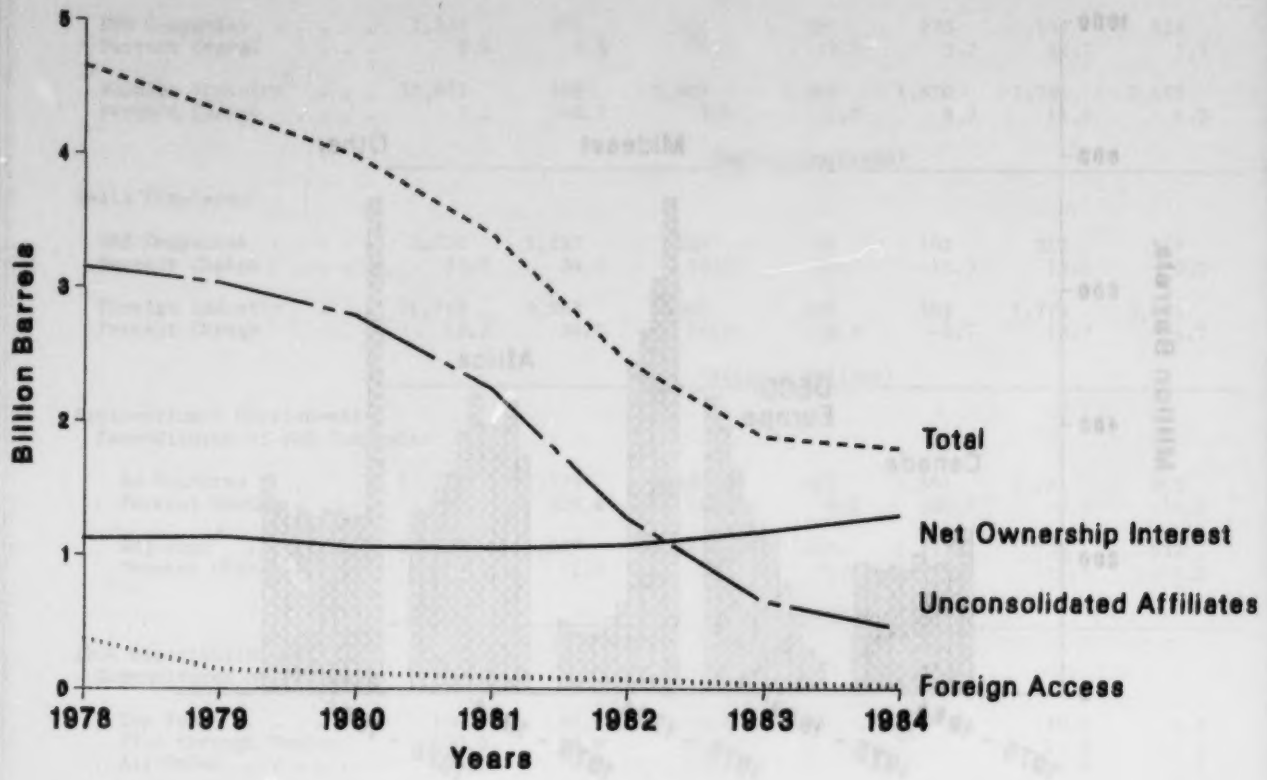
Sources: •FRS companies: Form EIA-28. •Industry Data: see Tables G36, G37, G38, and G39 in Appendix G.

Figure 25. Geographical Composition of FRS Companies' Foreign Crude Oil Production, 1975-1984



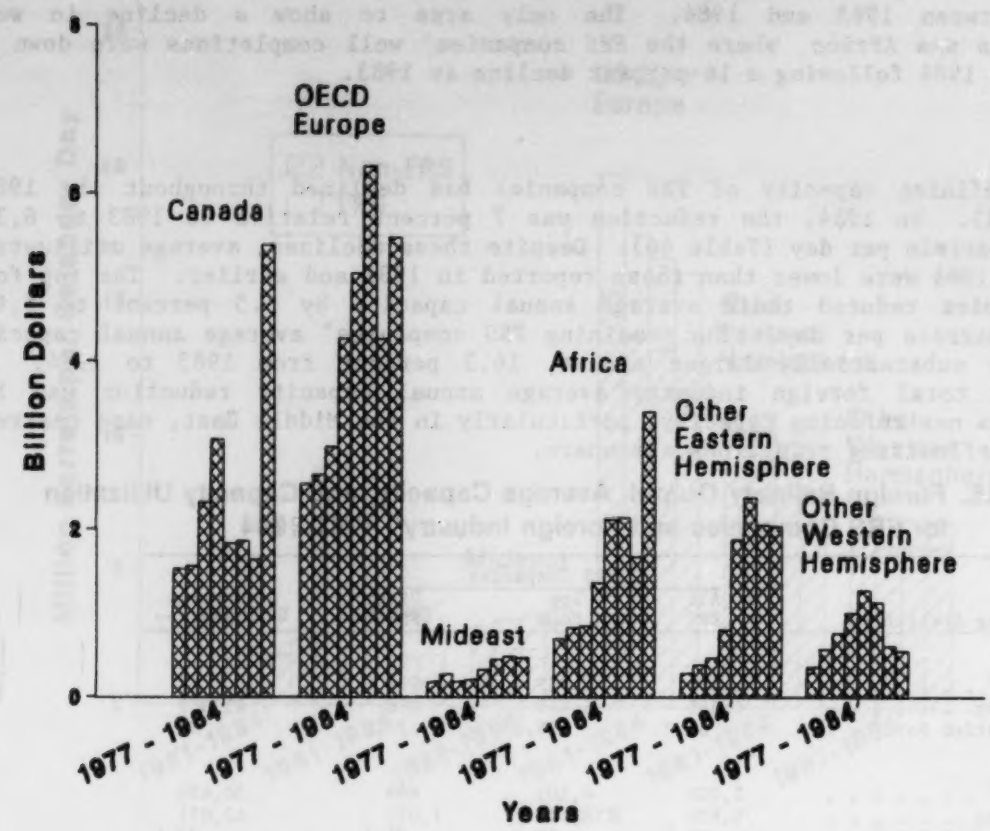
Source: Form EIA-28.

Figure 26. Foreign Crude Access for FRS Companies, 1978-1984



Source: Form EIA-28.

Figure 27. Foreign Exploration and Development Expenditures for FRS Companies, 1977-1984



Source: Form EIA-28.

Overall foreign well completions of the FRS companies rose 24 percent in 1984 (Table 45). The bulk of the increased activity stems from a surge in oil development well completions in Canada. Changes in Canadian energy policy, which moved oil prices in Canada closer to market levels, apparently led to accelerated efforts by the FRS companies to increase their Canadian oil production. Seven FRS companies reported at least a doubling of development oil well completions in Canada between 1983 and 1984. The only area to show a decline in well completions was Africa, where the FRS companies' well completions were down 11 percent in 1984 following a 16-percent decline in 1983.

Refining

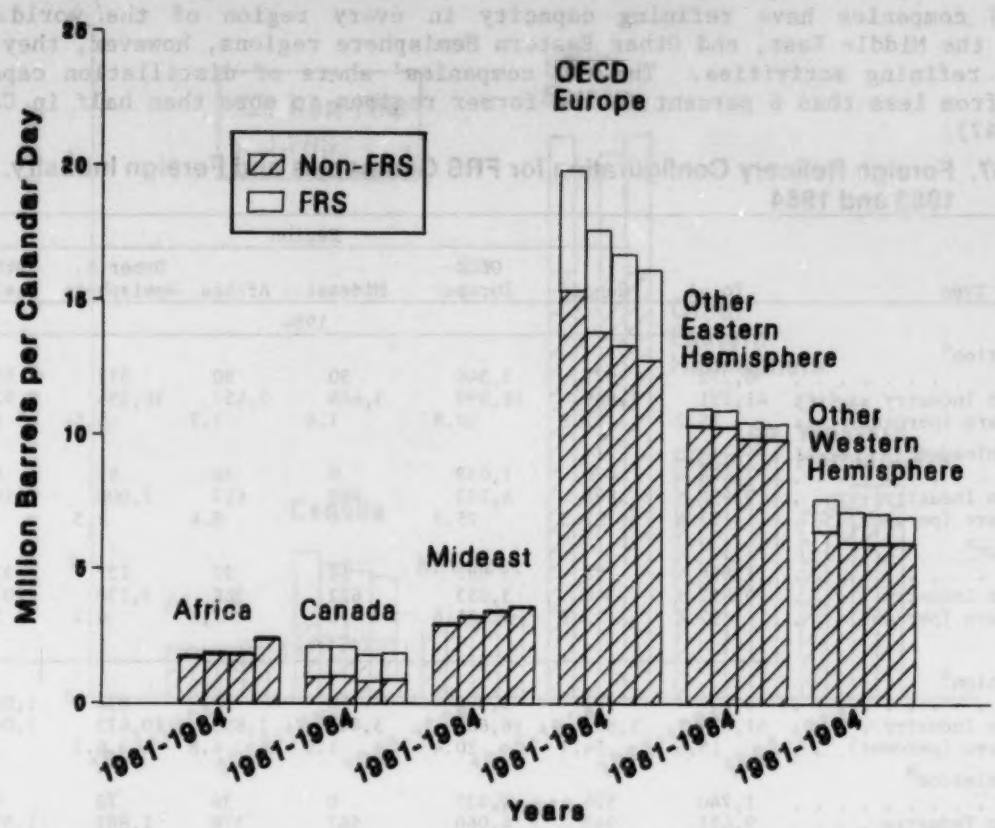
Foreign refining capacity of FRS companies has declined throughout the 1980s (Figure 28). In 1984, the reduction was 7 percent relative to 1983 to 6,365 thousand barrels per day (Table 46). Despite these declines, average utilization rates for 1984 were lower than those reported in 1981 and earlier. The top four FRS companies reduced their average annual capacity by 5.5 percent to 5,469 thousand barrels per day. The remaining FRS companies' average annual capacity fell by a substantially larger amount, 16.3 percent from 1983 to 1984. In aggregate, total foreign industry average annual capacity reduction was 1.7 percent, as new refining capacity, particularly in the Middle East, came onstream partially offsetting reductions elsewhere.

Table 46. Foreign Refinery Output, Average Capacity, and Capacity Utilization for FRS Companies and Foreign Industry[a], 1981-1984

Refining Statistics	FRS Companies			Foreign Industry
	All FRS	Top Four	Other FRS[b]	
1984				
Output[c]	4,696	3,957	739	NA
Capacity	6,365	5,469	896	41,359
Utilization Rate[d]	61.2	58.6	77.0	NA
1983				
Output[c]	5,000	4,101	899	30,474
Capacity	6,856	5,785	1,071	42,071
Utilization Rate[d]	59.5	57.3	71.1	72.4
1982				
Output[c]	5,473	4,521	952	30,455
Capacity	7,625	6,342	1,283	43,985
Utilization Rate[d]	58.1	57.2	62.5	69.4
1981				
Output[c]	6,161	5,221	940	31,940
Capacity	8,050	6,652	1,399	45,591
Utilization Rate[d]	63.7	64.0	62.2	70.1

[a]Foreign industry defined as all areas outside the United States (including Puerto Rico and the Virgin Islands) except the People's Republic of China, the Soviet Union and Eastern European countries considered part of the Soviet Bloc.
[b]Five through twelve and all other categories combined to prevent disclosure.
[c]For FRS companies, represents output at own refineries for own account plus output at other's refineries for own account.
[d]Utilization based on total crude oil throughput at own refineries for own account divided by average annual refinery capacity.
NA = Not available.
Note: Capacity and output are in thousand barrels per day.
Sources: •FRS companies: Form EIA-28. •Industry data: see Table G50, in Appendix G.

Figure 28. Distribution of Foreign Distillation Capacity, 1981-1984



Source: Compiled from Oil and Gas Journal, December 28, 1981, December 27, 1982, December 26, 1983, and December 31, 1984.

The FRS companies' share of total industry foreign refinery distillation capacity fell from 15.6 percent in 1983 to 15.2 percent in 1984 (based on year-end capacity). Similarly, their share of octane/unleaded and heavy/sour crude capacity declined in 1984 (Figure 29 and Figure 30). The FRS companies' share of octane/unleaded capacity fell from 18.5 percent to 17.4 percent, while their share of heavy/sour capacity fell from 19.9 percent to 17.6 percent (Table 47). The FRS companies have refining capacity in every region of the world. In Africa, the Middle East, and Other Eastern Hemisphere regions, however, they have limited refining activities. The FRS companies' share of distillation capacity ranges from less than 6 percent in the former regions to more than half in Canada (Table 47).

Table 47. Foreign Refinery Configuration for FRS Companies and Foreign Industry, 1983 and 1984

Capacity Type	Total	Region					
		Canada	OECD Europe	Mideast	Africa	Other E. Hemisphere	Other W. Hemisphere
	1984						
Distillation[a]							
FRS	6,272	977	3,346	50	90	572	955
Foreign Industry	41,291	1,869	16,099	3,608	2,457	10,394	6,923
FRS Share (percent)	15.2	52.3	20.8	1.4	3.7	5.5	13.8
Octane/Unleaded[b]							
FRS	1,678	470	1,038	0	36	51	84
Foreign Industry	9,626	898	4,103	605	417	2,008	1,594
FRS Share (percent)	17.4	52.3	25.3	0	8.6	2.5	5.3
Heavy/Sour[c]							
FRS	1,654	198	987	0	22	137	311
Foreign Industry	9,417	346	3,853	622	288	3,230	1,078
FRS Share (percent)	17.6	57.2	25.6	0	7.6	4.2	28.8
	1983						
Distillation[a]							
FRS	6,457	977	3,398	50	90	634	1,085
Foreign Industry	41,427	1,807	16,689	3,444	1,890	10,473	7,063
FRS Share (percent)	15.6	54.1	20.4	1.5	4.8	6.1	15.4
Octane/Unleaded[b]							
FRS	1,740	524	1,025	0	36	72	84
Foreign Industry	9,421	942	4,060	567	378	1,882	1,592
FRS Share (percent)	18.5	55.6	25.2	0	9.5	3.8	5.3
Heavy/Sour[c]							
FRS	1,862	211	1,164	0	22	154	311
Foreign Industry	9,367	353	3,966	377	291	3,295	1,085
FRS Share (percent)	19.9	59.8	29.3	0	7.6	4.7	28.7

[a]For distillation capacity, the sums of the regions do not equal the totals due to differences among the data sources.

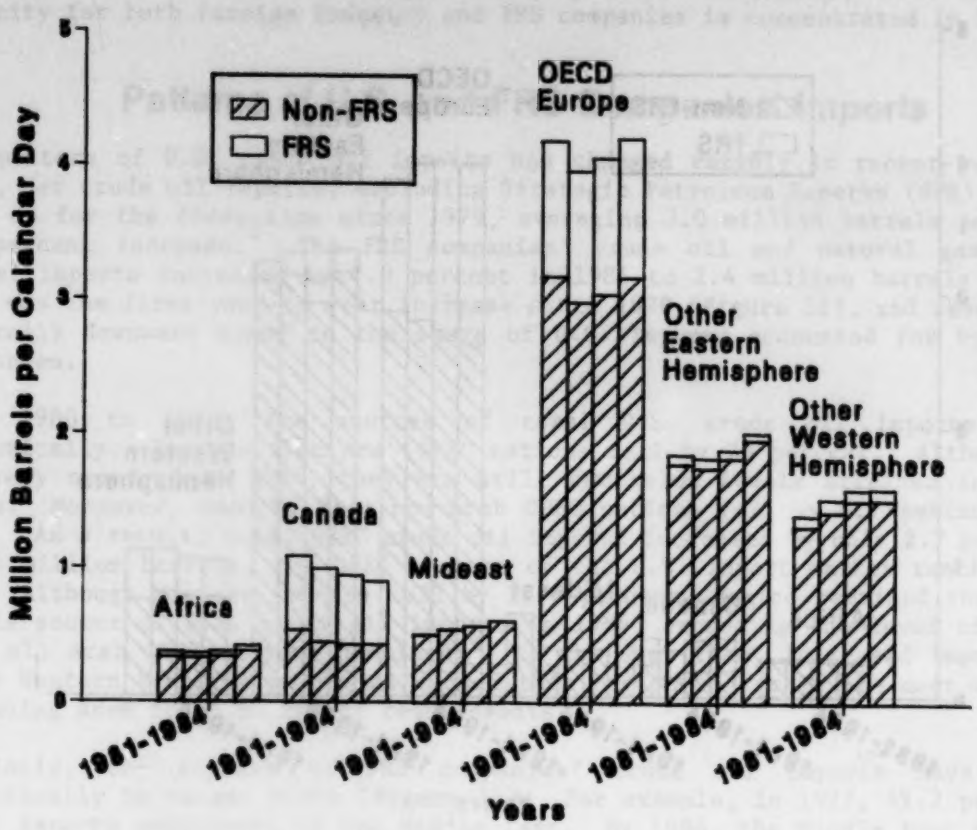
[b]Includes catalytic reforming, fresh feed catalytic cracking, hydrocracking, and alkylation capacities.

[c]Includes hydrotreating and hydrorefining capacities exclusive of pretreated catalytic reformer feed, naphtha desulfurization, and naphtha olefin or aromatics saturation.

Note: All capacities are in thousand barrels per calendar day.

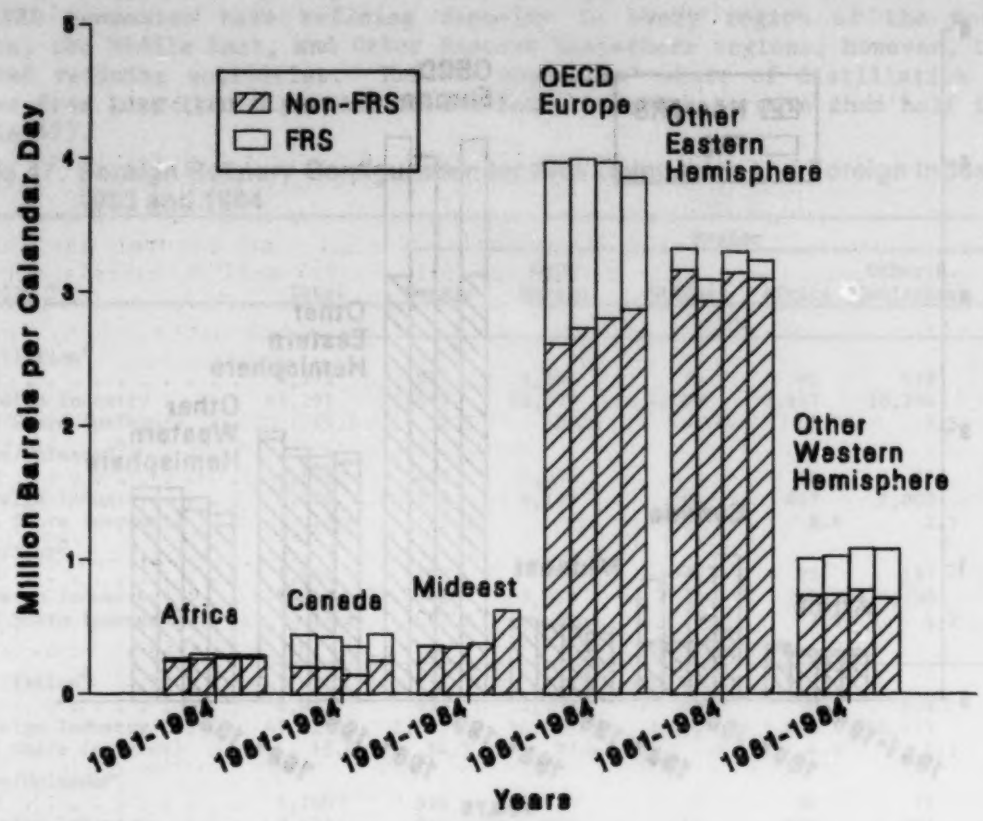
Sources: •Total FRS distillation capacity: Form EIA-28. •Foreign Industry total distillation capacity: Energy Information Administration, International Energy Annual (1983-1984). •All other capacities: compiled from Oil and Gas Journal (December 26, 1983, and December 31, 1984).

Figure 29. Distribution of Foreign Gasoline Capacity, 1981-1984



Source: Compiled from Oil and Gas Journal, December 28, 1981, December 27, 1982, December 26, 1983, and December 31, 1984.

Figure 30. Distibution of Foreign Heavy/Sour Capacity, 1981-1984



Source: Compiled from Oil and Gas Journal, December 28, 1981, December 27, 1982, December 26, 1983, and December 31, 1984.

With the exception of Canada and Europe, the foreign refining industry tends to have less sophisticated refineries than in the United States. This is true for both FRS and non-FRS refineries, which indicates that foreign refinery configurations are, in large part, determined by the nature of local demand. As shown in Figure 29, gasoline capacity is concentrated in Europe, where FRS companies have most of their gasoline capacity. Similarly, most heavy/sour capacity for both foreign industry and FRS companies is concentrated in Europe.

Patterns of U.S. and FRS Companies' Imports

The pattern of U.S. crude oil imports has changed rapidly in recent years. In 1984, net crude oil imports, excluding Strategic Petroleum Reserve (SPR) imports, were up for the first time since 1979, averaging 3.0 million barrels per day, a 4.0-percent increase.[3] The FRS companies' crude oil and natural gas liquids (NGLs) imports increased by 7.0 percent in 1984 to 2.4 million barrels per day. This was the first year-to-year increase since 1978 (Figure 31), and reversed the generally downward trend in the share of U.S. imports accounted for by the FRS companies.

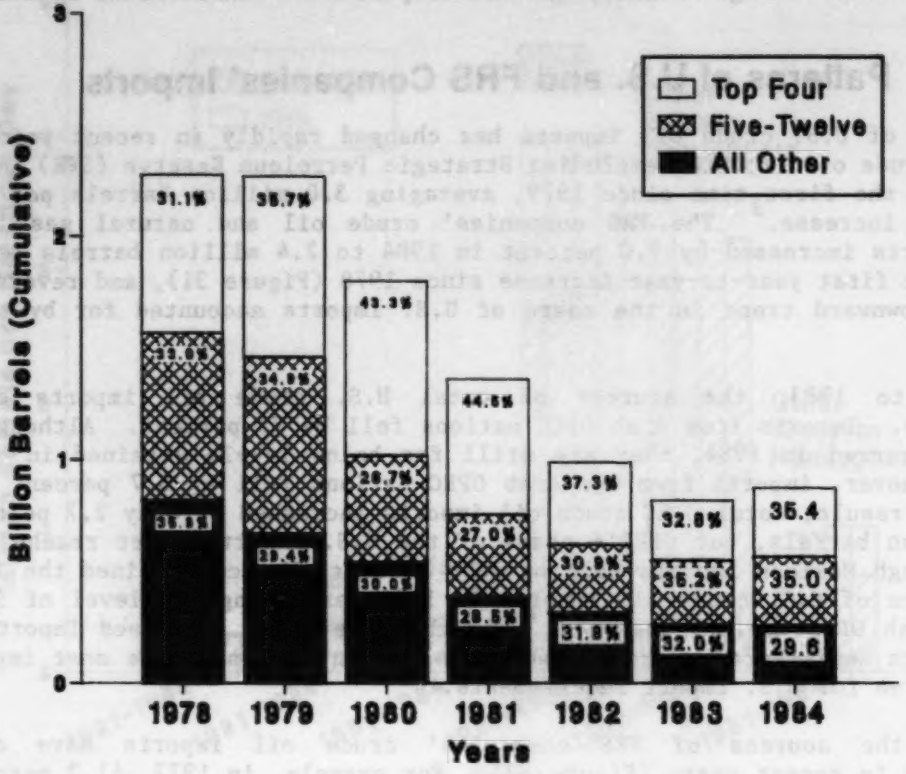
From 1980 to 1983, the sources of total U.S. crude oil imports changed dramatically. Imports from Arab OPEC nations fell by 73 percent. Although some recovery occurred in 1984, they are still far below levels attained in earlier years. Moreover, imports from non-Arab OPEC nations fell by 6.7 percent during 1984. As a result, total OPEC crude oil imports increased by only 2.7 percent to 553.4 million barrels, but OPEC's share of the U.S. import market reached a new low. Although Mexican imports fell by 13.8 percent, Mexico remained the largest single source of U.S. crude oil imports in 1984, exceeding the level of imports from all Arab OPEC nations combined.[4] At the same time, increased imports from other Western Hemisphere sources caused this region to remain the most important producing area for U.S. import requirements.

Similarly, the sources of FRS companies' crude oil imports have changed dramatically in recent years (Figure 32). For example, in 1977, 41.2 percent of their imports originated in the Middle East. By 1984, the Middle East accounted for only 14.8 percent (Table 48). Almost 40 percent of FRS crude oil imports originated in the Western Hemisphere in 1984. This is in contrast to less than 13 percent in 1977. The FRS companies have also reduced the share of non-Arab OPEC countries in their crude oil imports. The total OPEC share fell from 86.4 percent in 1977 to 49.4 percent in 1983 and 1984. Arab OPEC imports fell from 48.2 percent in 1977 to 20.4 percent in 1984.

For the United States, net imports of all major petroleum products except residual fuel oil were at higher levels during 1984 than 1983. Refined petroleum products from foreign refineries accounted for 13 percent of the U.S. products supplied during 1984.[5] Gross imports of gasoline increased for the fourth consecutive year (18 percent to 291 thousand barrels per day) and accounted for 4 percent of the 6.7 million barrels per day of gasoline consumed in 1984.

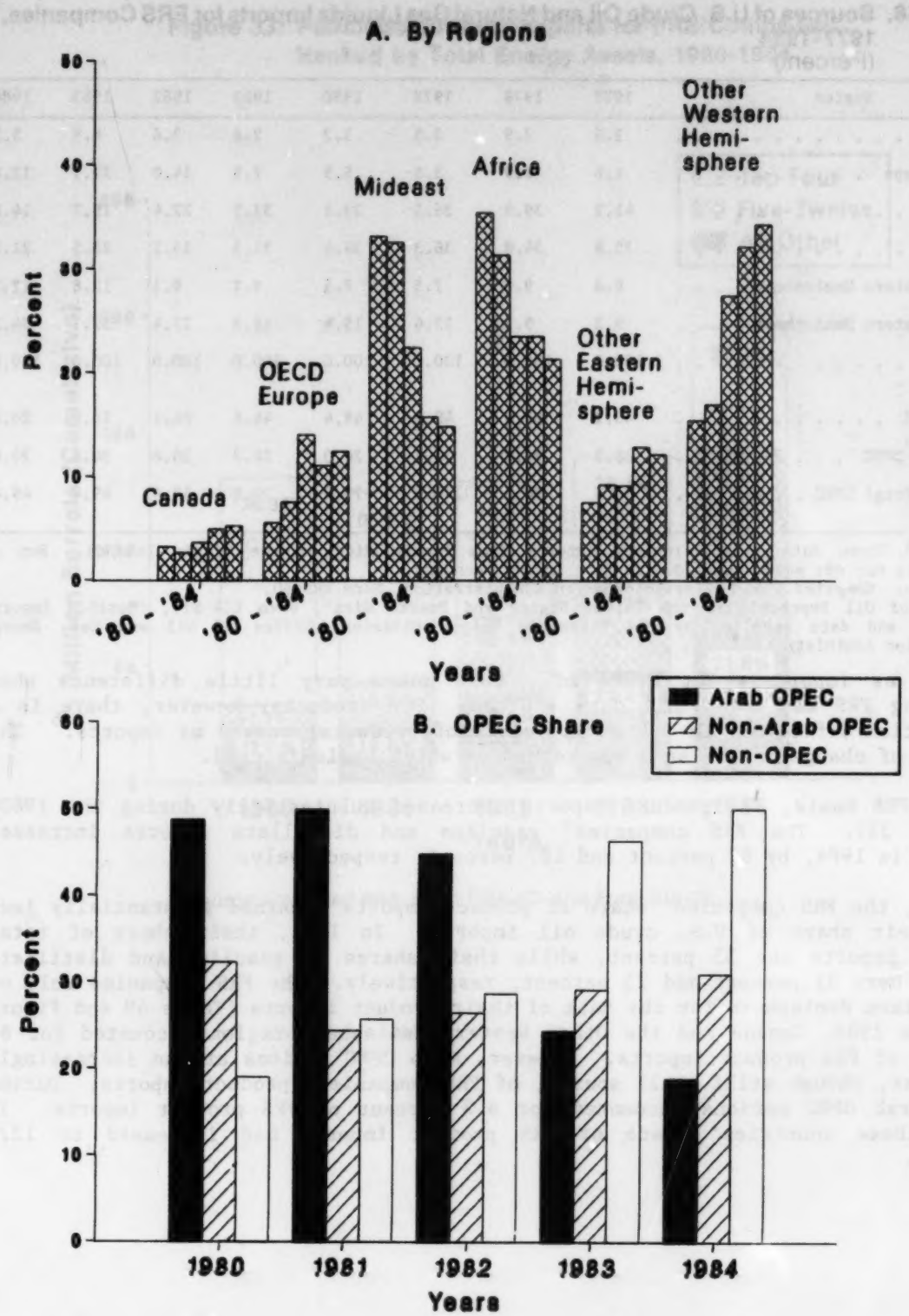
For the FRS companies, the United States includes Puerto Rico and the U.S. Virgin Islands. As a result, shipments from these areas are not considered imports, but shipments into these areas from countries other than the United States are

Figure 31. Net Domestic Crude Oil and NGL Imports for FRS Companies Ranked by Total Energy Assets, 1978-1984



Source: Form EIA-28.

Figure 32. Sources of FRS Crude Oil Imports, 1980-1984



Source: Compiled from Form ERA-60, and Form EIA-28.

Table 48. Sources of U.S. Crude Oil and Natural Gas Liquids Imports for FRS Companies, 1977-1984
(Percent)

Region	1977	1978	1979	1980	1981	1982	1983	1984
Canada	3.6	2.9	3.5	3.2	2.6	3.6	4.9	5.2
OECD Europe	1.6	2.9	3.6	5.5	7.5	14.0	11.1	12.4
Mideast	41.2	39.9	36.5	33.1	32.5	22.4	15.7	14.8
Africa	35.8	34.8	36.3	35.4	31.3	23.5	23.5	21.3
Other Eastern Hemisphere	8.6	9.8	7.5	7.5	9.2	9.1	12.8	12.1
Other Western Hemisphere	9.2	9.7	12.6	15.4	16.9	27.4	32.1	34.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Arab OPEC	48.2	48.4	48.2	49.4	44.6	24.1	18.8	20.4
Non-Arab OPEC	38.2	36.2	32.1	24.3	26.2	28.8	30.6	29.0
Total OPEC	86.4	84.6	80.2	73.8	70.8	52.9	49.4	49.4

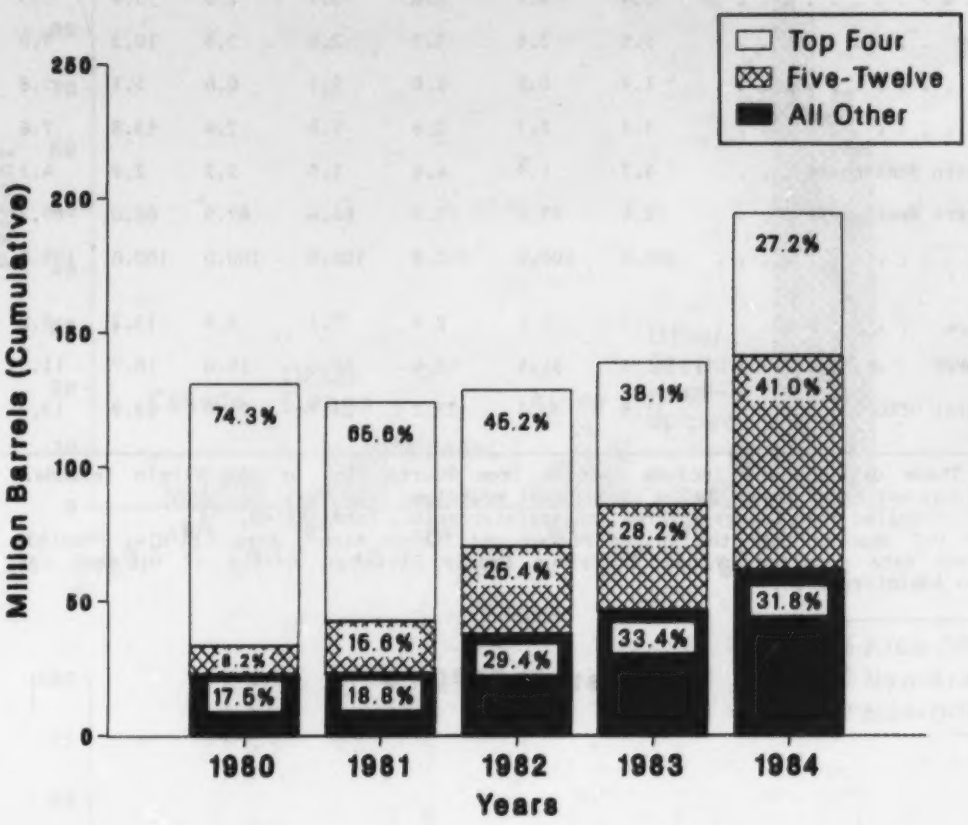
Note: These data do not include imports from Puerto Rico or the Virgin Islands. Sum of components may not eqaul total due to independent rounding.
Source: Compiled from Energy Information Administration, Form ERA-60, "Report of Oil Imports into the United States and Puerto Rico", Form EIA-814, "Monthly Imports Report," and data supplied by the Petroleum Supply Division, Office of Oil and Gas, Energy Information Administration.

counted as imports. For crude oil, this makes very little difference when comparing FRS and other EIA data sources. For products, however, there is a substantial difference in the total volume of products counted as imports.[6] The pattern of change is the same regardless of which basis is used.

On the FRS basis, FRS product imports increased substantially during the 1980s (Figure 33). The FRS companies' gasoline and distillate imports increased sharply in 1984, by 62 percent and 187 percent, respectively.

However, the FRS companies' share of product imports remained substantially less than their share of U.S. crude oil imports. In 1984, their share of total product imports was 35 percent, while their shares of gasoline and distillate imports were 21 percent and 23 percent, respectively. The FRS companies rely on the Western Hemisphere for the bulk of their product imports (Table 49 and Figure 34). In 1984, Canada and the Other Western Hemisphere region accounted for 66 percent of FRS product imports. However, Arab OPEC nations are an increasingly important, though still small source, of FRS companies' product imports. During 1981, Arab OPEC nations accounted for 6.8 percent of FRS product imports. In 1984, these countries' share of FRS product imports had increased to 12.7 percent.

Figure 33. Petroleum Product Imports for FRS Companies Ranked by Total Energy Assets, 1980-1984



Source: Compiled from Form ERA-60, and Form EIA-28.

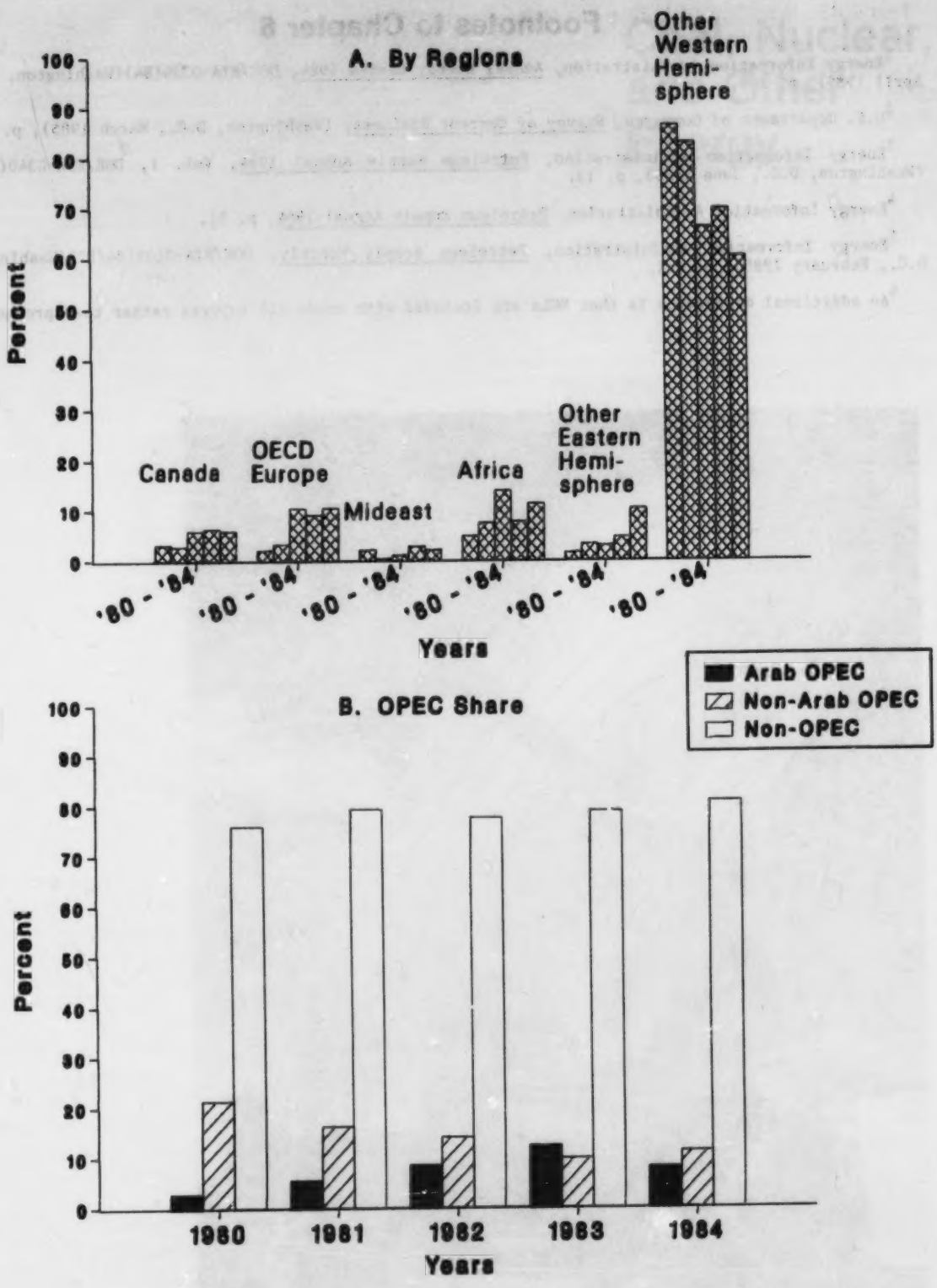
Table 49. Sources of U.S. Petroleum Product Imports for FRS Companies, 1977-1984
(Percent)

Region	1977	1978	1979	1980	1981	1982	1983	1984
Canada	2.4	3.5	4.6	3.1	2.8	5.9	6.3	5.9
OECD Europe	9.5	3.6	7.2	2.0	3.3	10.3	9.0	10.4
Mideast	1.9	0.8	1.8	2.1	0.4	1.1	2.8	2.1
Africa	3.1	2.7	2.6	4.8	7.4	13.8	7.6	11.2
Other Eastern Hemisphere	4.7	5.9	4.6	1.5	3.2	2.9	4.5	10.2
Other Western Hemisphere	78.4	83.5	79.3	86.4	82.9	66.0	69.7	60.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Arab OPEC	0.7	1.7	2.8	5.3	6.8	13.2	8.0	12.7
Non-Arab OPEC	31.1	31.5	22.4	16.6	15.0	10.7	11.2	18.7
Total OPEC	31.8	33.2	25.2	21.9	21.8	23.9	19.2	31.4

Note: These data do not include imports from Puerto Rico or the Virgin Islands. Sum of components may not equal total due to independent rounding.

Source: Compiled from Energy Information Administration, Form ERA-60, "Report of Oil Imports into the United States and Puerto Rico", Form EIA-814, "Monthly Imports Report," and data supplied by the Petroleum Supply Division, Office of Oil and Gas, Energy Information Administration.

Figure 34. Sources of Petroleum Product Imports for FRS Companies, 1980-1984



Source: Compiled from Form ERA-60, and Form EIA-28.

Footnotes to Chapter 6

[1]Energy Information Administration, Annual Energy Review 1984, DOE/EIA-0384(84)(Washington, D.C., April 1985), p. 209.

[2]U.S. Department of Commerce, Survey of Current Business, (Washington, D.C., March 1985), p. 30.

[3]Energy Information Administration, Petroleum Supply Annual 1984, Vol. 1, DOE/EIA-0340(84)/1 (Washington, D.C., June 1985), p. 13.

[4]Energy Information Administration, Petroleum Supply Annual 1984, p. 51.

[5]Energy Information Administration, Petroleum Supply Monthly, DOE/EIA-0109(84/12)(Washington, D.C., February 1985), p. xvi.

[6]An additional difference is that NGLs are included with crude oil imports rather than products.

Chapter 7

Coal, Nuclear, and Other Energy

Parabolic Dish Soler Collector

7. Coal, Nuclear, and Other Energy

In 1984, the coal industry experienced a banner year in terms of overall production and demand. The FRS companies' coal operations benefited particularly from these developments. Production rose relative to total industry and market share reached 25 percent. At the same time, net income from coal operations rose more than 20 percent. Some FRS companies' rates of return exceeded those obtained from petroleum operations for the first time.

In contrast, uranium operations yielded negative results. Sales and production declined and operating losses exceeded $150 million. In the past 4 years, FRS companies' operating losses have exceeded $500 million. Company efforts to withdraw from this line of business, evident since 1982, continued in 1984.

The most notable development with respect to other energy activities involved the emergence of geothermal heat extraction as a significant line of business. While oil shale and coal gasification were being phased out, new geothermal investments more than tripled to $578 million in 1984. For the first time, investment in a renewable energy source dominated the FRS companies' nonconventional energy resource development efforts.

Coal

Total U.S. production of bituminous coal and lignite rebounded from a steep decline in 1983 to establish a new high of 891.8 million tons in 1984--nearly 7 percent higher than the previous production record set in 1982. The FRS companies accounted for 36 percent of the total increase in 1984 (Table 50). As a result, the FRS companies' share of total production grew to 25.3 percent, up from 24 percent in 1983.

Over half of the industry increase was in the eastern coal producing states where production grew from 379.0 million tons in 1983 to 439.9 million tons in 1984 (Table 51). Approximately two-thirds of the 61-million-ton increase in the East was due to a rebound in production from underground mine operations which were especially hard hit during the 1983 production slump.

With respect to regional production for the FRS companies, western states continue to account for an increasing share of the FRS companies' domestic coal production (Figure 35). During 1984, as East region FRS production returned to its 1982 level, after falling 8.9 million tons in 1983, West and Midwest FRS production increased by a combined 31.8 million tons, 30.7 million tons higher than in 1982.

The FRS companies are responsible for most (68.3 percent) of the net increase in total U.S. bituminous and lignite production since 1977. Their participation is not confined by geographic region or mining technology. Only FRS eastern surface-mined coal, which grew steadily through 1981 (and showed a slight tonnage increase in 1982), has lost market share in recent years--from 13.6 percent in 1980 to 10.0 percent in 1984.

However, differences in the components of the FRS group of coal producers in 1974 and 1984 reveal a pattern, not of concentration, but of dispersion. In 1974 six FRS companies reported coal production of 87.4 million tons or 14.5 percent of

Table 50. Operating and Financial Items in Coal for FRS Companies and Domestic Industry, 1981-1984

Operating and Financial Items	1981	1982	1983	1984	Percent Change 1983-1984
	(million short tons)				
Domestic Production[a]					
FRS Companies	154.8	195.2	185.2	226.0	22.0
Domestic Industry	818.4	833.5	778.0	891.8	14.6
FRS Share (percent)	18.9	23.4	23.8	25.3	
Domestic Dispositions[a]					
FRS Companies	166.1	188.5	185.0	220.5	19.2
Domestic Industry	813.9	808.6	784.6	885.4	12.9
FRS Share (percent)	19.8	23.3	22.8	25.0	
	(million dollars)				
Financial Items for FRS Companies					
Operating Revenues	4,204.0	5,168.6	4,819.5	5,472.1	13.5
Operating Income	229.5	364.9	461.1	657.4	42.6
Additions to Investment in Place[b]	2,937.2	2,084.0	1,115.8	989.9	-11.3

[a]Includes bituminous coal and lignite, excludes anthracite. Domestic dispositions include exports.

[b]Measured as additions to property, plant, and equipment (PP&E) plus investments and advances.

Note: Sum of components may not equal total due to independent rounding.

Sources: oFRS companies: Form EIA-28. oIndustry Data: Production: Energy Information Administration, Quarterly Coal Report April-June 1985, DOE/EIA-0121(85/2Q)(Washington, D.C., October 18, 1985), p. 69; oDisposition: See footnotes, Table 51.

Table 51, Production, Dispositions, and Prices of Coal for FRS Companies and Domestic Industry, 1981-1984

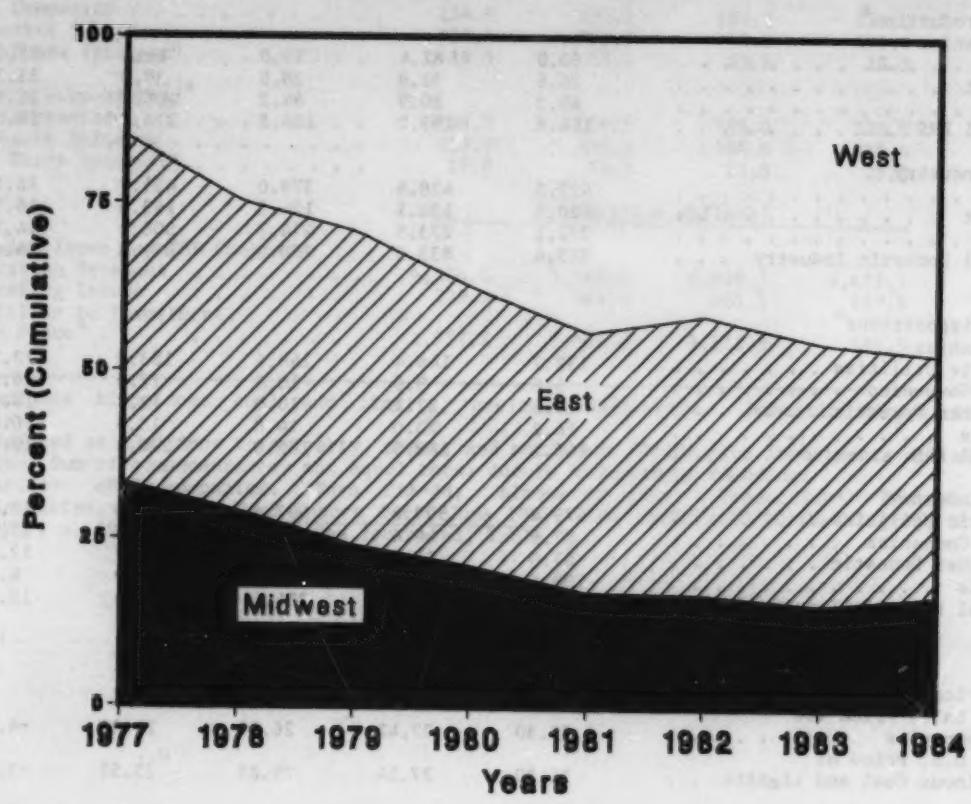
Production, Dispositions, and Prices	1981	1982	1983	1984	Percent Change 1983-1984
	(million short tons)				
Domestic Production[a]					
FRS Companies					
East	60.0	81.4	72.5	81.4	12.3
Midwest	26.5	32.9	28.5	38.0	33.3
West	68.3	80.9	84.2	106.5	26.5
Total FRS	154.8	195.2	185.2	226.0	22.0
Domestic Industry					
East	427.5	428.6	379.0	439.9	16.1
Midwest	120.8	131.1	124.3	143.6	15.5
West	270.1	273.9	274.7	308.3	14.2
Total Domestic Industry	818.4	833.5	778.0	891.8	14.6
Domestic Dispositions[a]					
FRS Companies					
Electric Utilities	132.7	146.4	148.6	183.0	23.2
Steel Companies	5.6	8.0	10.8	12.5	16.2
All Other Domestic	11.6	11.1	10.9	12.7	16.6
Exports	16.2	23.0	14.8	12.3	-16.6
Total FRS	166.1	188.5	185.0	220.5	19.2
Domestic Industry					
Electric Utilities	579.4	599.8	597.6	680.0	13.8
Steel Companies	57.9	40.6	37.4	43.7	17.0
All Other Domestic	67.0	64.9	72.9	81.7	12.2
Exports	109.6	103.2	76.8	79.9	4.1
Total Domestic Industry	813.9	808.6	784.6	885.4	12.9
	(dollars per short ton)				
Average Prices					
Average Sales Price for FRS Companies	25.30	27.42	26.06	24.81	-4.8
Average U.S. Price of Bituminous Coal and Lignite	26.29	27.14	25.85	25.51	-1.3

[a]Includes bituminous coal and lignite, excludes anthracite. See the Glossary for definitions of coal regions.

Note: Sum of components may not equal total due to independent rounding.

Sources: •FRS companies: Form EIA-28. •Industry: Production and Prices: Energy Information Administration, Coal Production 1984, DOE/EIA-0118(85/2Q)(Washington, D.C., November 8 1985), pp. 103, 104; •Industry Dispositions: Coal Distribution Janaury-December 1984, DOE/EIA-0125 (84/4Q) (Washington, D.C., April 1985), pp. 88, 90, 92, 94; Export: Coal Distribution January-December 1981, DOE/EIA-0125(81/4Q)(Washington, D.C., April 1982), p. 11; Coal Distribution Report January-December 1982, DOE/EIA-0125(83/4Q)(Washington, D.C., March 1983), p. 13; Coal Distribution Report January December 1983, DOE/EIA-0125(83/4Q)(Washington, D.C, April 1984), p. 12: and Coal Distribution January-December 1984, DOE/EIA-0125(84/4Q)(Washington, D.C., April 1985), p. 10.

Figure 35. Geographic Composition of Domestic Bituminous Coal and Lignite Production for FRS Companies, 1977-1984



Source: Form EIA-28.

the U.S. total production, an average of 14.6 million tons or 2.4 percent of total U.S. production. By 1977 the FRS average production share had decreased to 1.3 percent, as 10 reporting companies produced an average of 8.9 million tons. With 18 FRS companies reporting coal production in 1984, average production and average percentage share increased slightly to 12.6 million tons and 1.4 percent--still significantly below comparable averages in 1974.

The distribution of 885.4 million tons of coal by the domestic industry in 1984 represented a gain of 100.8 million tons over 1983. Coal distributed to electric utilities continues to predominate, showing a 13.8-percent gain of 82.4 million tons after falling by 2.2 million tons in 1983. Developments in export markets have been less favorable. Exports regained only 2.1 million tons of a 26.4-million-ton drop in 1983. Strong competition from Australia, South Africa, Poland, Canada, and recently, Columbia leave the United States as the swing supplier in export coal markets.

For the second time in as many years, both the FRS companies and the overall domestic industry evidenced declines in the average price of coal (excluding anthracite) of 4.8 percent and 1.3 percent, respectively, in 1984. Both FRS and other industry producers report idle capacity relative to demand. However, for FRS companies, reported excess capacity is at a 6-year low. This reflects increasing overall market penetration and a slowing in the rate of new capacity expansion.

Among the FRS companies there were two major acquisitions in 1984: Chevron acquired Pittsburg & Midway Coal Company and its 742 million tons of coal reserves with the acquisition of Gulf Oil. Texaco acquired 243 million tons of coal reserves with its takeover of Getty in March 1984. These mergers did not change the FRS group's position in the coal industry. Other transactions, however, resulted in disposals of about 1.0 billion tons of coal reserves in 1984 to non-FRS companies. As a result, the value of coal assets for FRS companies did not grow in 1984 despite capital outlays of nearly $1 billion.

The FRS companies' capital outlays for coal operations have declined steadily since 1981 from $2.9 billion to $1.0 billion in 1984 (Table 50). In contrast, operating income from the coal operations of the FRS companies was strong in 1984, having advanced more than 42 percent from $461.1 million in 1983 to $657.4 million in 1984. Coal's contribution to net income of the FRS companies reflects the best performance so far recorded. Apparent rates of return on committed assets now begin to approach those for chemicals and upstream petroleum operations.

Nuclear

The year 1984 marked the sixth consecutive year in which no new orders were placed for nuclear power plants. As a consequence of the long-term decline, producers (including FRS companies) are abandoning active participation in the market. Production of uranium oxide (U_3O_8) by the domestic industry fell 42 percent from 23.5 million pounds in 1983 to 13.6 million pounds in 1984 (Table 52). Among the FRS companies, the proportionate decrease was somewhat less (37.8 percent), as the FRS production share rose from 28.1 percent in 1983 to 30.1 percent in 1984.

Table 52. Operating and Financial Items in Nuclear for FRS Companies and Domestic Industry, 1981-1984

Operating and Financial Items	1981	1982	1983	1984	Percent Change 1983-1984
		(million pounds)			
Domestic Production of U_3O_8					
FRS Companies	14.5	9.2	6.6	4.1	-37.8
Domestic Industry	39.2	26.8	23.5	13.6	-42.1
FRS Share (percent)	37.0	34.3	28.1	30.1	NM
		(million dollars)			
Financial Items for FRS Companies					
Additions to Investment in Place[a]	264.4	115.3	61.6	46.2	-24.9
Operating Income	-224.6	-128.2	22.0	-150.2	NM

[a]Measured as additions to property, plant, and equipment (PP&E) plus investments and advances.
NM = Not meaningful.
Note: Sum of components may not equal total due to independent rounding.
Sources: •FRS companies: Form EIA-28. •Industry Data: Energy Information Administration, Uranium Industry Annual 1984, DOE/EIA-0478(84)(Washington, D.C., October 22, 1985), p. 44.

Financial results for the FRS companies' nuclear operations in 1984 returned to their downward trend after a brief upturn in 1983. Operating income dropped from a positive $22 million in 1983 to a negative $150.2 million in 1984. The year 1983 remains the only year for which a positive figure has been reported by the FRS companies for the nuclear segment's operating income. With respect to additions to investment in place, the FRS companies showed nearly a 25-percent decline from $61.7 million in 1983 to $46.2 million in 1984.

Other Energy

The continued existence of worldwide surplus crude oil capacity and uncertainties about the stability of oil and natural gas prices have made many FRS companies wary of investing in most nonconventional energy sources in recent years. Although in 1984 FRS additions to other energy property, plant, and equipment (PP&E) in the United States increased by more than 36 percent over 1983 to $652 million, they remained at less than half of the $1.3 billion level of 1982 (Table 53). Foreign outlays showed a small decrease in this same period, from $177.6 million to $172.2 million. Seventy-two percent of the FRS foreign expenditures in other energy involve Canadian tar sands operations. Most of the balance is associated with geothermal development.

Domestic investment by FRS companies has fallen off significantly in all of the nonconventional categories except geothermal. Excluding geothermal, additions to PP&E for domestic nonconventional energy in 1984 amounted to only 6 percent of 1982 expenditures. However, the sharp increase in domestic investment in geothermal-related PP&E ($433 million or nearly 300 percent) resulted in the overall 36.2 percent increase in total domestic additions to PP&E shown in Table 53.

Table 53. Investment and Income in Other Energy for FRS Companies, 1981-1984

Other Energy Segments	1981	1982	1983	1984	Percent Change 1983-1984
	(million dollars)				
Additions to PP&E					
Domestic					
Oil Shale	321.4	1,003.1	199.1	36.6	-81.6
Coal Gasification/Liquefaction and Tar Sands	38.1	5.2	9.3	2.0	-78.4
Geothermal	99.9	135.0	145.0	578.0	298.6
Solar and Other	49.8	171.9	125.3	35.2	-71.9
Total Domestic	509.2	1,315.2	478.7	651.8	36.2
Foreign					
Tar Sands	177.5	147.6	147.1	123.8	-15.9
Other	31.2	23.4	30.5	48.4	58.5
Total Foreign	208.7	171.0	177.6	172.2	-3.1
Total Additions to PP&E	717.9	1,486.2	656.3	823.9	25.5
Operating Income					
Domestic	-451.0	-580.5	-436.5	-394.4	NM
Foreign	-32.4	46.4	205.8	196.5	-4.5
Total Operating Income	-483.4	-534.1	-230.7	-197.9	NM

NM = Not meaningful.
Note: Sum of components may not equal total due to independent rounding.
Source: Form EIA-28.

During 1984, Phillips Petroleum purchased Geyser Geothermal Company from R. J. Reynolds Industries and R. J. Reynolds Energy Company for an estimated $213 million as part of their acquisition of Aminoil. Unocal paid $285 million for an additional 25-percent interest in The Geysers, a geothermal resource venture, from Diamond Shamrock, giving Unocal a 75-percent interest in the venture. These two companies produced natural steam in 1984 for approximately 1,800 megawatts of electric generating power in the United States and the Philippines.

Table 54 also provides an indication of the changing relative importance of nonconventional energy sources to the FRS companies. The 1984 share of nonconventional energy net PP&E allocated to domestic oil shale (42.0 percent) and Canadian tar sands (28.2 percent) still dominates the nonconventional energy spectrum for FRS companies. However, the relative importance of domestic renewable energy activities is on the rise. In 1984, 26 percent of net PP&E in other energy went to renewables. As recently as 1981, the share was 11 percent.

Domestic operating income from nonconventional energy activities continued to show a loss in 1984 and totaled a negative $394.4 million. This was smaller by $42.1 million than the operating losses incurred in 1983. In the foreign area, operating income was $196.5 million in 1984 as compared with $205.8 million in 1983. Although evidencing a slight decline from 1983, income from foreign nonconventional energy activities was considerably higher than pre-1983 levels. This improvement largely reflects a favorable climate in energy pricing policies in Canada relating to production of oil from tar sands.

Table 54. Distibution of Net PP&E in Other Energy for FRS Companies, Selected Years, 1975-1984

Other Energy Segments	1975	1978	1981	1982	1983	1984
	(percent)					
Domestic						
Synthetic Fuels						
Oil Shale	[a]	10.8	25.9	40.7	47.7	42.0
Tar Sands and Coal Gasification/ Liquefaction	[a]	1.2	3.2	1.2	1.4	1.5
Total Domestic Synthetic Fuels	31.0	12.0	29.1	41.9	49.2	43.5
Renewable Energy						
Geothermal	[a]	4.8	8.0	9.1	11.3	20.2
Solar and Other	[a]	1.3	2.8	7.1	7.3	5.8
Total Domestic Renewable Energy	7.7	6.1	10.9	16.2	18.6	26.0
Total Domestic	38.7	18.1	40.0	58.1	67.8	69.5
Foreign						
Tar Sands	[b]	[b]	56.1	38.9	29.5	28.2
Other	[b]	[b]	3.3	3.0	2.7	2.3
Total Foreign	61.3	81.9	60.0	41.9	32.2	30.5
Total Other Energy	100.0	100.0	100.0	100.0	100.0	100.0

[a]Data withheld to prevent disclosure.
[b]Data not collected prior to 1981.
Note: Sum of components may not equal total due to independent rounding.
Source: Form EIA-28.

Research and Development Expenditures

Aggregate spending on research and development by FRS companies rose 7 percent in 1984 relative to 1983. For the past several years, the composition of spending by functional area has been relatively stable. Spending on energy related R&D has tended to decline relative to that spent on nonenergy. This, however, is more a function of change in reporting companies due to the entrance of Du Pont and U.S. Steel to the FRS reporting group in 1982 than a change in strategies.

Overall, increased funding for conventional energy R&D, mostly petroleum related, has been at the expense of the nonconventional. Funding for tar sand development and coal derived synthetic fuels has been cut by nearly 60 percent since 1981 (Table 55) .

Table 55. Worldwide Research and Development Expenditures by FRS Companies, 1981-1984

Uses	1981	1982	1983	1984	Percent Change 1983-1984
	(million dollars)				
Petroleum					
Oil and Gas Recovery	668.0	751.8	756.3	692.4	-8.4
Other Petroleum	468.1	495.3	487.1	614.4	26.1
Total Petroleum	1,136.2	1,247.2	1,243.3	1,306.8	5.1
Coal, Conventional	36.0	45.7	33.5	34.7	3.4
Nuclear	35.1	96.6	88.8	95.1	7.1
Other Energy					
Oil Shale	91.7	104.5	91.2	106.5	16.9
Tar Sands	60.8	51.7	30.6	26.7	-12.5
Coal Gasification/Liquefaction	268.4	223.4	159.0	102.2	-35.7
Solar and Geothermal	52.4	53.9	53.2	54.5	2.5
Other	64.9	56.1	53.8	85.9	59.7
Total Other Energy	538.2	489.6	387.7	375.8	-3.1
Total Energy	1,745.4	1,879.1	1,753.3	1,812.5	3.4
Nonenergy	958.2	1,839.4	1,970.7	2,157.3	9.5
Unassigned	116.4	155.6	88.3	94.0	6.4
Total	2,820.0	3,874.1	3,812.3	4,063.8	6.6

Note: Sum of components may not equal total due to independent rounding.
Source: Form EIA-28.

Glossary

Acquisition: The procurement of the legal right to explore for and produce discovered minerals, if any, within a specific area; that legal right may be obtained by mineral lease, concession, or purchase of land and mineral rights, or of mineral rights alone.

Acquisition Costs: Direct costs and indirect costs incurred to acquire legal rights to wasting natural resources. Direct costs include costs incurred to obtain options to lease or purchase mineral rights and costs incurred for the actual leasing (e.g., lease bonuses) or purchasing of the rights. Indirect costs include such costs as: brokers' commissions and expenses; abstract and recording fees; filing and patenting fees; and costs of legal examination of title and documents.

Acreage: An area, measured in acres, that is subject to ownership or control by those holding total or fractional shares of working interests. Acreage is considered developed when development has been completed. (See definition for Working Interest.) A distinction may be made between "gross" acreage and "net" acreage:

- Gross. All acreage covered by any working interest, regardless of the percentage of ownership in the interest.
- Net. Gross acreage adjusted to reflect the percentage of ownership in the working interest in the acreage.

Affiliate: An "affiliate" of, or a person "affiliated" with, a specific person is a person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the person specified. The term "affiliate" includes any subsidiary or parent of the person specified.

- Person. An individual, or any legal entity such as a corporation, a partnership, an association, a joint-stock company, a trust, or an unincorporated organization.
- Control. Including the terms "controlling," "controlled by" and "under common control with", means the possession, direct or indirect, or the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting shares, by contract, or otherwise.

Amortization: The depreciation, depletion, or charge-off to expense of intangible and tangible assets over a period of time. In the extractive industries, the term is most frequently applied to mean either (1) the periodic charge-off to expense of the costs associated with nonproducing mineral properties incurred prior to the time when they are developed and entered into production or (2) the systematic charge-off to expense of those costs of productive mineral properties (including tangible and intangible costs of prospecting, acquisition, exploration, and development) that had been initially capitalized (or deferred) prior to the time the properties entered into production, and thereafter are charged off as minerals are produced.

Branded Product: A refined petroleum product sold by a refiner with the understanding that the purchaser has the right to resell the product under a trademark, trade name, service mark, or other identifying symbol or names owned by such refiner.

Chemical Operations: All petrochemical and plastics operations.

Christmas Tree: The valves and fittings installed at the top of a well to control and direct the flow of well fluids.

Coal Gasification: The conversion of coal into a gas, which can be burned as a fuel or processed into chemicals or fuels.

Coal Liquefaction: The conversion of coal into a liquid which can be burned as a fuel or processed into chemicals or fuels.

Coal Regions: The following regional definitions are used to report domestic coal reserves, production, and other operating statistics.

- Eastern Region. Consists of the Northern Appalachian Coal Basin. The following States comprise the Eastern Region:

Alabama	Pennsylvania
Georgia	Virginia
Ohio	Tennessee
Maryland	North Carolina
Mississippi	West Virginia

Eastern Kentucky

Eastern Kentucky is defined to include the following counties: Bell, Boyd, Breathitt, Carter, Clay, Clinton, Elliott, Estill, Floyd, Greenup, Harlan, Jackson, Johnson, Knott, Knox, Laurel, Lawrence, Less, Leslie, Letcher, Lewis, McCreary, Madison, Magoffin, Martin, Menifee, Morgan, Owsley, Perry, Pike, Powell, Pulaski, Rockcastel, Rowan, Wayne, Whitley, and Wolfe.

- Midwest Region. Consists of the Illinois and Michigan Coal Basins. The following States comprise the Midwest Region:

Illinois	Michigan
Indiana	Western Kentucky

Western Kentucky is defined to include the following counties: Bulter, Christian, Crittenden, Caldwell, Daviess, Edmonson, Grayson, Hancock, Hart, Henderson, Hopkins, Logan, McLean, Muhlenberg, Ohio, Todd, Union, Warren, and Webster.

- Western Region. Consists of the Northern Rocky, Southern Rocky, Western Interior, and West Coast Coal Basins. The following States comprise the Central Western Region.

Iowa	Idaho
Kansas	Colorado
Missouri	Utah
Oklahoma	Arizona
Arkansas	New Mexico
Texas	Alaska
North Dakota	Washington
South Dakota	Oregon
Montana	California
Wyoming	Louisiana

Company Automotive (Retail) Outlet: Any retail outlet selling motor fuel under a reporting company brand name. (See definition for Branded Product.)

- Company Operated. A company retail outlet which is operated by salaried or commission personnel paid by the reporting company.
- Lessee. An independent marketer who leases the station and land and has use of tanks, pumps, signs, etc. A lessee dealer typically has a supply agreement with a refiner or a distributor and purchases products at dealer tank wagon prices. The term "lessee dealer" is limited to those dealers who are supplied directly by a refiner or any affiliate or subsidiary company of a refiner. "Direct supply" includes use of commission agent or common carrier delivery.
- Open. An independent marketer who owns or leases (from a third party who is not a refiner) the station or land of a retail outlet and has use of tanks, pumps, signs, etc. An open dealer typically has a supply agreement with a refiner or a distributor and purchases products at or below dealer tank wagon prices.

Condensate (Lease Condensate): A natural gas liquid recovered from associated and nonassociated gas well gas from lease separators or field facilities, reported in barrels of 42 U.S. gallons at atmospheric pressure and 60° F. For FRS reporting, condensate that is commingled with the crude oil stream should be reported as crude, (see definition for Crude Oil) otherwise it is reported as a plant product (see plant products).

Contribution To Net Income: The FRS segment equivalent of net income. However, many consolidated items of revenue and expense are not allocated to the segments, and therefore they are not equivalent in a strict sense. The largest item not allocated to the segments is interest expense since this is regarded as a corporate level item for FRS purposes.

Crude Oil: A mixture of hydrocarbons that existed in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. For FRS reporting, volumes reported as crude include:

- Liquids technically defined as crude oil.
- Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure

after being recovered from oil well (casinghead) gas in lease separators and are commingled with the crude stream without being separately measured (see definition for Condensate).

- Small amounts of nonhydrocarbons produced with the oil.

Statistical data pertaining to crude oil production and reserves are reported as liquid equivalents at the surface (excluding base sediment and water) measured in terms of stock tank barrels of 42 U.S. gallons at atmospheric pressure, corrected to 60° F.

Where a State regulatory agency specifies a definition of crude oil which differs from that set forth above for statistical purposes, the State definition should be followed.

DD&A: Abbreviation for depreciation, depletion and amortization.

Deferred Taxes: Taxes accrued and reflected as an expense in a company's income statement, but not payable to the taxing authority in that time period. These taxes are accrued to compensate for an understatement of income tax expense which would occur if only the tax currently due to the taxing authority were reflected as the total income tax expense.

Depletion: A term for either (1) a periodic assignment to expense of recorded amounts or (2) an allowable income tax deduction that is related to the exhaustion of mineral reserves. Depletion is included as one of the elements of amortization. When used in that manner, depletion refers only to book depletion (see definition for Amortization).

- Book: The portion of the carrying value (other than the portion associated with tangible assets) prorated in each accounting period, for financial reporting purposes, to the extracted portion of an economic interest in a wasting natural resource.

- Tax-cost: A deduction (allowance) under U.S. Federal Income taxation normally calculated under a formula whereby the adjusted basis of the mineral property is multiplied by a fraction, the numerator of which is the number of units of minerals sold during the tax year and the denominator of which is the estimated number of units of unextracted minerals remaining at the end of the tax year plus the number of units of minerals sold during the tax year.

- Tax-percentage (or Statutory): A deduction (allowance) allowed to certain mineral producers under U.S. Federal income taxation calculated on the basis of a specified percentage of gross revenue from the sale of minerals from each mineral property not to exceed the lesser of 50 percent of the taxable income from the property computed without allowance for depletion. (There are also other limits on percentage depletion on oil and gas production.) The taxpayer is entitled to a deduction representing the amount of tax-cost depletion or percentage (statutory) depletion, whichever is higher.

- Excess Statutory Depletion: The excess of estimated statutory depletion allowable as an income tax deduction over the amount of cost

depletion otherwise allowable as a tax deduction, determined on a total enterprise basis.

Depreciation: See definition for Amortization.

Development: The preparation of a specific mineral deposit for commercial production; this preparation includes construction of access to the deposit and of facilities to extract the minerals. The development process is sometimes further distinguished between a preproduction stage and a current stage, with the distinction being made on the basis of whether the development work is performed before or after production from the mineral deposit has commenced on a commercial scale.

Development Costs: Costs incurred to obtain access to proved reserved and to provide facilities for extracting, treating, gathering, and storing the oil and gas.

Domestic Operations: Domestic operations are those operations located in the United States.

The United States is defined as the 50 States, including their offshore territorial waters, the District of Columbia, and U.S. commonwealth, territories, and protectorates.

For FRS reporting, "domestic" is segregated between Alaska and other domestic (consisting of all domestic other than Alaska).

Drilling: The act of boring a hole (1) to determine whether minerals are present in commercially recoverable quantities and (2) to accomplish production of the minerals (including drilling to inject fluids).

- Exploratory. Drilling to locate probable mineral deposits or to establish the nature of geological structures; such wells may not be capable of production if minerals are discovered.
- Developmental: Drilling to delineate the boundaries of a known mineral deposit to enhance the productive capacity of the producing mineral property.
- Directional: Drilling that is deliberately made to depart significantly from the vertical.

Drilling and Equipping of Wells: Cost incurred in the drilling and equipping of wells through completion of the "christmas tree."

Dry-Hole Charge: The charge-off to expense of a previously capitalized cost upon the conclusion of an unsuccessful drilling effort.

Equity in Earnings of Unconsolidated Affiliates: A company's proportional share (based on ownership) of the net earnings or losses of an unconsolidated affiliate.

Exploration: Exploration involves (1) identifying areas that may warrant examination and (2) examining specific areas that are considered to have prospects of containing oil and gas reserves, including drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property.

Exploration Costs: Costs, including depreciation and applicable operating costs, of support equipment and facilities and other costs directly identifiable with exploration activities, such as:

- Costs of topographical, geological, and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these costs are sometimes referred to as geological and geophysical or "G&G" costs.

- Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on the properties, legal costs for title defense, and the maintenance of land and lease records.

- Dry hole contributions and bottom hole contributions.

- Costs of drilling and equipping exploratory wells.

- Costs of drilling exploratory-type stratigraphic test wells.

Extraordinary Item: Income and expense items associated with events and transactions that possess a high degree of abnormality and are of a type that would not reasonably be expected to recur in the foreseeable future. An example would be losses resulting from an earthquake, expropriation, or a prohibition under a newly enacted law.

Field: An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

Footage Drilled: Total footage for wells in various categories, as reported for any specified period, includes (1) the deepest total depth (length of well bores) of all wells drilled from the surface, (2) the total of all bypassed footage drilled in connection with reported wells, and (3) all new footage drilled for directional "sidetrack" wells. Footage reported for directional "sidetrack" wells does not include footage in the common bore which is reported as footage for the original well. In the case of old wells drilled deeper, the reported footage is that which was drilled below the total depth of the old well.

- Deepest Total Depth. The deepest total depth of a given well is the distance from a surface reference point (usually the Kelly bushing) to the point of deepest penetration measured along the well bore. If a

well is drilled from a platform or barge over water, the depth of the water is included in the total length of the well bore.

- Sidetrack Drilling. this is a remedial operation that results in the creation of a new section of well bore for the purpose of (1) detouring around junk, (2) redrilling lost hole, or (3) straightening key seats and crooked holes. Directional "sidetrack" wells do not include footage in the common bore which is reported as footage for the original well.

Foreign Access: Refers to proved reserves of crude and condensate, natural gas liquids applicable to long-term supply agreements with foreign governments or authorities in which the company acts as producer.

Foreign Operations: These are operations that are located outside the United States. (See definition for Domestic Operations.) Determination of whether an enterprise's mobile assets, such as offshore drilling rigs or ocean-going vessels, constitute foreign operations should depend on whether such assets are normally identified with operations located outside the United States.

Foreign operations are segregated into the following areas for FRS reporting purposes:

- OECD Europe: Includes Austria, Belgium, Denmark, Finland, France, the Federal Republic of Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.

- Middle East: Includes Saudi Arabia, the United Arab Emirates, Iraq, Iran, Kuwait, the Iraq-Saudi Arabia Neutral Zone, Qatar, Dubai, Bahrain, Oman, Yemen, Syria, Jordan, and Israel.

- Canada.

- Africa (the African continent).

- Other Eastern Hemisphere: Areas eastward of the Greenwich prime meridian to 180° longitude and not included in other specified domestic or foreign classifications.

- Other Western Hemisphere: Areas westward of the Greenwich prime meridian to 180° longitude not included in other domestic or foreign classifications.

Funds From Operations: Calculated by adding non-cash charges back to net income or contribution to net income. Deferred taxes and depreciation, depletion, and amortization (DD&A) are the largest non-cash charges.

Funds, Total Sources Of: The total source of funds including net income plus non-cash charges such as DD&A and deferred taxes, issuances of stocks and bonds, and proceeds from the sale or property, plant, and equipment. The concept is similar to cash flow generated, but does not attempt to account for changes in working capital items. Thus, for example, an inventory buildup or drawdown

would not be accounted for under the "funds" concept since both cash and inventory are items of working capital.

Geological and Geophysical (G&G) Costs: Costs incurred in making geological and geophysical studies, including, but not limited to, costs incurred for salaries, equipment, obtaining rights of access, and supplies for scouts, geologists, and geophysical crews.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in either the gaseous, liquid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (e.g., methane, a constituent of natural gas) to the very heavy and very complex.

Improved Recovery: The operation whereby crude oil or natural gas is recovered using any method other than those that rely primarily on the use of natural reservoir pressure, gas lift or the use of a pump.

Intangible Drilling and Development Costs (IDC): Costs incurred in preparing well locations, drilling and deepening wells, and preparing wells for initial production up through the point of installing control valves. None of these functions, because of their nature, have salvage value. Such costs would include labor, transportation, consumable supplies, drilling tool rentals, site clearance, and similar costs.

Investment and Advances to Unconsolidated Affiliates: The balance sheet account representing the cost of investments and advances to unconsolidated affiliates. Generally, affiliates which are less than 50 percent owned by a company may not be consolidated into the company's financial statements.

Lease Bonus: An amount paid by a lessee to a lessor as consideration for granting a lease, usually as a lump sum; this payment is in addition to any rental or royalty payments.

Lease Equipment: All equipment located on the lease except the well to the point of the "christmas tree."

Lifting Costs: The costs associated with the extraction of a mineral reserve from a producing property. (See definition for Production Cost.)

Milling: The grinding or crushing of ore, concentration, and other beneficiation including the removal of valueless or harmful constituents and preparation for market.

Milling Capacity: The maximum rate at which a mill is capable of treating ore or producing concentrate.

Mining: Any activity directed to the extraction of ore and associated rock. Included are open pit work, quarrying, augering, alluvial dredging, and combined operations, including surface and underground operations.

Mineral: Any of the various naturally occurring substances (such as coal, crude oil, metals, natural gas, salt, sand, stone, sulfur, and water) usually obtained

from the earth. The term is used to include all wasting, i.e., nonregenerative, inorganic substances that are extracted from the earth.

Mineral Interests In Properties: (Hereinafter referred to as Properties): These include fee ownership or a lease, concession, or other contractual interest representing the right to extract minerals subject to such terms as may be imposed by the conveyance of those interests. Properties also include royalty interests, production payments payable in oil or gas, and other nonoperating interests in properties operated by others. Properties include those agreements with foreign governments or authorities under which an enterprise participates in the operation of the related properties or otherwise serves as "producer" of the underlying reserves, but properties do not include other supply agreements or contracts that represent the right to purchase (as opposed to extract) oil and gas.

Mineral Lease: An agreement wherein a mineral interest owner (lessor) conveys to another party (lessee) the rights to explore for, develop, and produce specified minerals. The lessee acquires a working interest and the lessor retains a nonoperating interest in the property, referred to as the royalty interest, each in proportions agreed upon.

Mineral Rights: The ownership of the minerals beneath the earth's surface with the right to remove them. Mineral rights may be conveyed separately from surface rights.

Minority Interest in Income: The proportional share of the minority ownership's interest (less than 50 percent) in the earnings or losses of the consolidated subsidiary.

Subsidiaries are generally fully consolidated when a share of ownership between 51 percent and 100 percent is held by the parent. In consolidation, 100 percent of revenues, expenses, assets, etc. are included in the financial statements even though, for example, the subsidiary is only 80 percent owned by the parent company. In such cases, the consolidated balance sheet must have a caption on the right-hand side titled something like "minority interests in consolidated affiliates," and the income statement must have a similar line to reduce net income to the pro rata (80 percent in this example) share of the consolidated subsidiary's net income.

Motor Gasoline: Refers to blended gasoline suitable as fuel for use in spark ignition systems and within American Society for Testing and Materials (ASTM) specifications D 439.

Natural Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons usually contained in the mixture are methane, ethane, propane, butanes, and pentanes. Typical nonhydrocarbon bases which may be present in reservoir natural gas are carbon dioxide, helium, hydrogen sulphide and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions thereof occur either in a single gaseous phase in the reservoir or in solution with crude oil and are not distinguishable at that time as separate substances.

Natural gas, based on the type of occurrence in the reservoir, is classified by two categories, as follows:

- Non-Associated Gas is natural gas that is not in contact with significant quantities of crude oil in the reservoir.
- Associated/Dissolved Gas is the combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Associated gas is free natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir. Dissolved gas is natural gas that is in solution with crude oil in the reservoir at reservoir conditions.

Statistical data pertaining to natural gas production and reserves are reported in units of 1,000,000 cubic feet (i.e., MMCF) at 14.73 pounds per square inch absolute and 60° F for FRS purposes.

Natural Gas Liquids (NGL): Natural gas liquids are those portions of reservoir gas which are liquefied at the surface in lease separators, field facilities, or gas processing plants. Natural gas liquids include but are not limited to: ethane, propane, butanes, pentanes, natural gasoline and condensate.

Net Investment In Place: The sum of net property, plant, and equipment (PP&E) plus investment and advances to unconsolidated affiliates.

Nonbranded Product: Any refined petroleum product that is not a branded product.

Nuclear Fuel Operations: All nuclear fuel operations, excluding reactor and reactor component manufacturing or containment construction. Includes: exploration and development; mining; milling; conversion; enrichment; fabrication; reprocessing; and spent fuel storages.

Offshore: That geographic area that lies seaward of the coastline. In general, the coastline is the line of ordinary low water along with that portion of the coast that is in direct contact with the open sea or the line marking the seaward limit of inland water.

If a State agency uses a different basis for classifying onshore and offshore areas, the State classification should be used. (Cook Inlet in Alaska is classified as offshore.)

Oil Shale: A sedimentary rock containing kerogen, a solid organic material.

Operating Expenses: Segment expenses related both to revenue from sales to unaffiliated customers and revenue from intersegment sales or transfers, excluding loss on disposition of property, plant, and equipment; interest expenses and financial charges; foreign currency translation effects; minority interest; and income taxes.

Operating Income: Operating revenues less operating expenses. Excludes items of other revenue and expense such as equity in earnings of unconsolidated affiliates, dividends, interest income and expense, income taxes, extraordinary items, and cumulative effect of accounting changes.

Operating Revenues: Segment revenues both from sales to unaffiliated customers (i.e., revenue from customers outside the enterprise as reported in the company's consolidated income statement) and from intersegment sales or transfers, if any, of product and services similar to those sold to unaffiliated customers, excluding equity in earnings of unconsolidated affiliates; dividend and interest income; gain on disposition of property, plant and equipment; and foreign currency translation effects.

Other Energy Operations: Energy operations not included in Petroleum, Coal, or Nuclear. Other Energy includes oil shale, tar sands, geothermal, and coal liquefaction and gasification.

PP&E, Additions to: The current year's expenditures on property, plant, and equipment (PP&E). The amount is predicated upon each reporting company's accounting practice. That is, accounting practices with regard to capitalization of certain items may differ across companies, and therefore this figure in FRS will be a function of each reporting company's policy.

PP&E, Net: The original cost of property, plant, and equipment (PP&E), less accumulated depreciation.

Petrochemicals: Organic and inorganic compounds and mixtures that include but are not limited to organic chemicals, cyclic intermediates, plastics and resins, synthetic fibers, elastomers, organic dyes, organic pigments, detergents, surface active agents, carbon black, and ammonia.

Petroleum: Hydrocarbon mixtures broadly defined to include crude oil, lease condensate, natural gas, products of natural gas processing plants (plant products), refined products, and semi-finished products and blending materials.

Pipelines, Rate Regulated: FRS establishes three pipeline segments; crude/liquid (raw materials); natural gas; and refined products. The pipelines included in these segments are all federally or state rate-regulated pipeline operations, which are included in the reporting company's consolidated financial statements. However, at the reporting company's option intra-state pipeline operations may be included in the Domestic Refining/Marketing Segment if: they would comprise less than 5 percent of Domestic Refining/Marketing Segment net PP&E, revenues and earnings in the aggregate; and if the inclusion of such pipelines in the consolidated financial statements adds less than $100 million to the net PP&E reported for the Domestic Refining/Market Segment.

Primary Recovery: The crude oil or natural gas recovered by any method that may be employed to produce them where the fluid enters the well bore by the action of natural reservoir pressure (energy or gravity).

Primary Transportation: Conveyance of large shipments of petroleum raw materials and refined products usually by pipeline, barge, or ocean-going vessel. All crude oil transportation is primary, including the small amounts

moved by truck. All refined product transportation by pipeline, barge, or ocean-going vessel is primary transportation.

Producing Property: A term often used in reference to a property, well, or mine that produces wasting natural resources. The term means a property that produces in paying quantities (that is, one for which proceeds from production exceed operating expenses).

Production, Natural Gas Liquids: Production of natural gas liquids is classified:

- Contract Production. Natural gas liquids accruing to a company because of its ownership of liquids extraction facilities that it uses to extract liquids from gas belonging to others, thereby earning a portion of the resultant liquids.
- Leasehold Production. Natural gas liquids produced, extracted, and credited to a company's interest.
- Contract Reserves. Natural gas liquid reserves corresponding to the contract production defined above.
- Leasehold Reserves. Natural gas liquid reserves corresponding to the leasehold production defined above.

Production, Oil and Gas: The lifting of the oil and gas to the surface and gathering, treating, field processing (as in the case of processing gas to extract liquid hydrocarbons), and field storage. The production function shall normally be regarded as terminating at the outlet valve on the lease or field production storage tank; if unusual physical or operational circumstances exist, it may be more appropriate to regard the production function as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal.

- Gross Company-Operated Production. Total production from all company operated properties including all working and non-working interests.
- Net Working Interest Production. Total production accruing to the reporting company's working interests less royalty oil and volumes due others.

Production Costs: Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. The following are examples of production costs (sometimes called lifting costs):

- Costs of labor to operate the wells and related equipment and facilities.
- Repair and maintenance costs.

- The costs of materials, supplies and fuel consumed and services utilized in operating the wells and related equipment and facilities.
- The costs of property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
- The costs of severance taxes.

Depreciation, depletion, and amortization (DD&A) of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

Production costs include the following sub-categories of costs:

- Well operations and maintenance
- Well workovers
- Operating fluid injection and improved recovery programs
- Operating gas processing plants
- Ad valorem taxes
- Production or severance taxes
- Other, including overhead

Production Payment: A contractual arrangement providing a mineral interest that gives the owner a right to receive a fraction of production or of proceeds from the sale of production, until a specified quantity of minerals (or a definite sum of money, including interest or a definite sum of money, plus interest) has been received. It is considered a nonoperating interest, since the owner bears no part of exploration, development, and operating costs. Usually, there is no recourse if production is insufficient to satisfy the amount of the production payment.

Production payments are classified according to the manner in which the rights were created:

- Carved-out. A production payment created out of the working interest in a mineral property. The working interest owner "carves out" and transfers the production payment contractual right to the transferee in return for cash or other consideration but retains the operating rights and responsibilities.
- Retained. Production payment retained under a contract in which the transferor divests a working interest in the producing property to the transferee and subsequently becomes the recipient of production payments delivered by the transferee.

Research and Development: Basic and applied research in the sciences and engineering and the design and development of prototypes and processes, excluding quality control, routine product testing, market research, sales promotion, sales service, research in the social sciences or psychology, and other non-technological activities or technical services.

Reserves (Coal): Coal reserve estimates comprising the demonstrated coal reserve base include only proved (measured) and probable (indicated).

- Proved (Measured) Reserves. Reserves or resources for which tonnage is computed from dimensions revealed in outcrops, trenches, workings, and drill holes and for which the grade is computed from the results of detailed sampling. The sites for inspection, sampling, and measurement are spaced so closely and the geologic character is so well defined that size, shape, and mineral content are well established. The computed tonnage and grade are judged to be accurate within limits which are stated, and no such limit is judged to be different from the computed tonnage or grade by more than 20 percent.

- Probable (Indicated) Reserves. Reserves or resources for which tonnage and grade are computed partly from specific measurements, samples, or production data and partly from projection for a reasonable distance on geologic evidence. The sites available are too widely or otherwise inappropriately spaced to permit the mineral bodies to be outlined completely or the grade established throughout.

Reserves, Proved (Oil and Gas): Proved Reserves for oil and gas are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by one or more of: actual production; conclusive formation test; core analysis; and electric or other log interpretation. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Volumes of petroleum raw materials placed in underground storage are not to be considered proved reserves, but should be classified as inventory.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs but is classified separately as

"indicated additional reserves;" (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

It is not necessary that production, gathering, or transportation facilities be installed or operative for a reservoir to be considered proved.

For natural gas an appropriate reduction in the reservoir gas volume is made to cover the removal of the liquefiable portions of the gas and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. If the liquefiable portions of the gas are not separately estimated, they need not be separately stated for FRS reporting purposes.

Reserves, Net: Includes all proved reserves associated with the company's net working interests. (See definition for Working Interest.)

Reserves, Change In: For FRS reporting, the following definitions should be used for changes in reserves.

- Revisions of Previous Estimates. Changes in previous estimates of proved reserves, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors. Revisions do not include changes in reserve estimates resulting from increases in proved acreage or from improved recovery techniques.

- Improved Recovery. Changes in reserve estimates resulting from application of improved recovery techniques shall be separately shown, if significant. If not significant, such changes shall be included in revisions of previous estimates.

- Purchases or Sales of Minerals-in-Place. Increase or decrease in the estimated quantity of reserves resulting from the purchase or sale of mineral rights in land with known proved reserves.

- Extensions, Discoveries, and Other Additions. Additions to an enterprise's proved reserves that result from (1) extension of the proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.

Reservoir: A porous and permeable underground formation containing an individual and separate accumulation of producible hydrocarbons (oil and/or gas) that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Residual Fuel: Topped crude obtained by refinery operations including light and heavy grades 5 and 6, heavy diesel fuel, type S-M diesel fuel, navy grade, navy special, bunker C, and acid sludge.

Royalty: A contractual arrangement providing a mineral interest that gives the owner a right to a fractional share of production or proceeds therefrom, that does not contain rights and obligations of operating a mineral property, and that is normally free and clear of exploration, developmental, and operating costs, except production taxes.

Semifinished (Petroleum) Products: Unfinished petroleum stocks, except those designated as raw materials. In most cases, these are produced by partial refining or purchased in an unfinished state for conversion to finished products by further refining.

Short Ton: A unit of weight that equals 2,000 pounds.

Support Equipment and Facilities: These include, but are not limited to, seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district, or field offices.

Surface Rights: Fee ownership in surface areas of land. Also used to describe a lessee's right to use as much of the surface of the land as may be reasonably necessary for the conduct of operations under the lease.

Tangible Development Costs: Cost incurred during the development stage for access, mineral-handling, and support facilities having a physical nature. In mining, such costs would include tracks, lighting equipment, ventilation equipment, other equipment installed in the mine to facilitate the extraction of minerals, and supporting facilities for housing and care of work forces. In the oil and gas industry, tangible development costs would include well equipment (such as casing, tubing, pumping equipment, and well heads), as well as field storage tanks and gathering systems.

Tar Sands: Bitumen-impregnated sands that yield mixtures of liquid hydrocarbon and which require further processing other than mechanical blending before becoming finished petroleum products.

Timing Differences: Differences between the periods in which transactions affect taxable income and the periods in which they enter into the determination of pretax accounting income. Timing differences originate in one period and reverse or "turn around" in one or more subsequent periods. Some timing differences reduce income taxes that would otherwise be payable currently; others increase income taxes that would otherwise be payable currently.

Transfer Price: The monetary value assigned to products, services, or rights conveyed or exchanged between related parties, including those occurring between units of a consolidated entity.

Uncompleted Wells, Equipment, and Facilities Costs: The costs incurred to (1) drill and equip wells that are not yet completed, and (2) acquire or construct equipment and facilities that are not yet completed and installed.

Undeveloped Property: Refers to a mineral property on which development wells or mines have not been drilled or completed to a point that would permit the production of commercial quantities of mineral reserves.

Well: A hole drilled in the earth for the purpose of (1) finding or producing crude oil or natural gas; or (2) providing services related to the production of crude oil or natural gas.

Wells are classified as (1) oil wells; (2) gas wells; (3) dry holes; (4) stratigraphic test wells; or (5) service wells. The latter two types of wells are not counted for FRS reporting.

Oil wells, gas wells, and dry holes are classified as exploratory wells or development wells. Exploratory wells are subclassified as (1) new-pool wildcats; (2) deeper-pool tests; (3) shallow-pool test; and (4) outpost (extension) tests. Well classifications reflect the status of wells after drilling has been completed.

- Completion. The term refers to the installation of permanent equipment for the production of oil or gas. If a well is equipped to produce only oil or gas from one zone or reservoir, the definition of a "well" (classified as an oil well or gas well) and the definition of a "completion" are identical. However, if a well is equipped to produce oil and/or gas separately from more than one reservoir, a "well" is not synonymous with a "completion."

- Completion Date. The date on which the installation of permanent equipment has been completed (for the production of oil or gas) as reported to the appropriate regulatory agency.

  - The date of completion of a dry hole is the date of abandonment as reported to the appropriate agency.

  - The date of completion of a service well is the date on which the well is equipped to perform the service for which it was intended.

- Development Well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

- Dry Hole. An exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

- Exploratory Well. A well that is not a development well, a service well, nor a stratigraphic test as those items are defined elsewhere herein.

- Oil Well. A well completed for the production of crude oil from at least one oil zone or reservoir.

Wellhead Price: The value at the mouth of the well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. Posted prices, requested prices, or prices as defined by lease agreements, contracts or tax regulations should be used where applicable.

Working Interest: An interest in a mineral property that entitles the owner of that interest to all of a share of mineral production from the property, usually subject to a royalty.

A working interest permits the owner to explore, develop and operate the property. The working interest owner bears the costs of exploration, development and operation of the property, and in return is entitled to a share of the mineral production from the property, or to a share of the proceeds therefrom. It may be assigned to another party in whole or in part, or it may be divided into other special property interests.

- Gross Working Interest. The reporting company's working interest plus the proportionate share of any basic royalty interest or overriding royalty interest related to the working interest.
- Net Working Interest. The reporting company's working interest not including any basic royalty or overriding royalty interests.

Yellowcake (U_3O_8): The final precipitate formed in the milling process. U_3O_8 common form of triuranium oxide, is the powder obtained by evaporating an ammonial solution of the oxide.

Appendix A

General Structure of the Reporting Format of the Financial Reporting System Form EIA-28

Appendix A

General Structure of the Reporting Format of the Financial Reporting System Form EIA-28

Appendix A

General Structure of the Reporting Format of The Financial Reporting System Form EIA-28

The structure of the FRS data system is designed to permit review of the functional performance of 26 energy companies in total, as well as specific functions and geographic areas of operation. The data reported by respondent firms are segregated by line-of-energy activity, as well as by geographic location. The financial reporting schedules in Form EIA-28 are designed to obtain data on revenues, cost, and profits, thereby indicating financial flows and performance characteristics for any given annual reporting period. In addition, the form collects balance sheet data (i.e., accumulated property, plant, and equipment, etc.), along with data on new investment in these accounts. To complement the financial data, a series of statistical schedules are included to trace physical activity patterns and to evaluate several physical/ financial relationships.

In greater detail, the structure of the reporting package is as follows:

A. Financial Reporting

1. The starting point is the three basic financial statements required by the SEC Form 10K:

   a. Consolidating Statement of Income (Schedule 5110),
   b. Selected Consolidating Financial Data (Balance Sheets)
   c. Statement of Sources and Uses of Funds (Schedule 5130).

2. Corporate-wide financial information is first disaggregated by energy type (referred to as lines-of-business) as follows:

a. Petroleum (5210)
   b. Coal (5310)
   c. Nuclear (5410)
   d. Other Energy (5510)
   e. Nonenergy: Chemical and Other Nonenergy (5610)

3. Nonenergy data is collected to describe Corporate resource investment strategy and to allow aggregation of the FRS detailed schedules into the consolidated company amounts.

B. Operating and Statistical Information

1. For each type of energy activity, complementary operating information is obtained through the following schedules:

   a. Petroleum (5241-5246)
   b. Coal (5341)
   c. Nuclear (5441)

2. The schedules are designed to correspond to the financial information so that level of effort in the financial sense can be compared to physical results.

C. Complementary Schedules:

1. Examine corporate research and development funding priorities (Schedule 5111)
2. Reveal impact of tax policy on financial results of reporting companies (Schedule 5112)
3. Monitor raw material acquisition and refined product disposition strategies of FRS companies (5211-5212)
4. Trace changes in reserve for petroleum (5246), coal (5341), and uranium (5410)

Segment Overview

Each line of business (e.g., petroleum, coal, nuclear) is further disaggregated into segments. These segments are presented as though each were a separate entity, with recognized limitations, entering into transactions with other segments and third parties.

The following lists each segment within each line of business and includes a brief description of that segment's principal revenue-generating product or service. (Further background on the FRS segments may be found in Appendix E. See the sections on "FRS Petroleum Supply and Trading Function" and "FRS Income Taxes.")

A. Petroleum

1. Domestic Production. Production and sales of domestic crude, natural gas, and natural gas liquids. Sales of domestic crude can only be made to the Domestic refining marketing segment for FRS purposes. Natural gas and natural gas liquids can be purchased from or sold directly to domestic/foreign third parties, unconsolidated affiliates, and other domestic/foreign segments.

2. Domestic Refining/Marketing. Purchases raw materials from domestic production, foreign refining/marketing and third parties for refining and/or sale to third parties. The segment also purchases directly from foreign production for companies that do not have foreign refining/marketing and imports all foreign purchases.

3. Rate Regulated Pipeline. Transports crude, natural gas, and natural gas liquids through federal or state regulated pipeline operations.

4. Foreign Production. Production and sales of foreign crude, natural gas and natural gas liquids. Sales are made to the foreign refining marketing segments unless the company does not have foreign refinery operations and imports all foreign purchases. Companies that meet these criteria may sell directly to domestic refining/marketing.

5. Foreign Refining/Marketing. Purchases raw materials from foreign production segments and domestic refining/marketing segments, refines and sells to third parties, and to domestic refining/-marketing segments.

6. International Marine. Provides high seas marine transportation of foreign source crude for third parties and for foreign and domestic source crude.

B. Coal

1. Domestic Coal. Production and sales of domestic coal and performance of contract mining services.
2. Foreign Coal. Production and sales of foreign coal.

C. Nuclear

1. Domestic Nuclear. Production and sales of domestic ore, yellowcake, uranium hexafluoride, fabricated products and performance of various nuclear services.

D. Other Energy

Includes sale and grant revenues for extracted domestic and foreign segments products from the following sources:

1. Oil Shale
2. Tar Sands
3. Geothermal
4. Coal Gasification/Liquefaction
5. Other

E. Nonenergy

Includes nonenergy activities such as retailing, manufacturing, etc. It also includes electric generation and the manufacture of generation equipment, including nuclear equipment. Raw materials and fuels for electric generation are included as energy segments above.

1. Domestic Chemical. Sales of domestic petrochemicals and plastics.
2. Foreign Chemical. Sales of foreign petrochemicals and plastics.
3. Domestic Other. Nonenergy revenues from all other domestic nonenergy activities.
4. Foreign Other Nonenergy. Same as above except foreign.

Index to FRS Reporting Schedules (Form EIA-28):

I. Consolidating Schedules (5100's)
Statement of Income (5110)
Research and Development Funding and Expenditures (5111)
Analysis of Income Taxes (5112)
Selected Consolidating Financial Data (5120)

Statement of Sources and Uses of Funds (5130)
Eliminations in Consolidations (5150)

II. Petroleum Schedules (5200's)

Domestic and Foreign Consolidating
Statement of Incomes (5210)
Refining/Marketing and Production Segments Refining Operations
Exploration and Production Operations (5211)
Purchases and Sales of Raw Materials and Refined Products (5212)
Domestic and Foreign Exploration, Development and Production Statistics (5241)
Domestic and Foreign jRefining Statistics (5242)
Sources and Disposition of Crude and Natural Gas Liquids (5245)
Proved Petroleum Reserves (5246)

III. Coal Schedules (5300's)

Domestic and Foreign Statement of Income (5310)
Domestic Coal Operations Reserves and Production Statistics (5341)

IV. Nuclear Schedules (5400's)

Domestic and Foreign Statement of Income (5410)
Domestic and Foreign Nuclear Fuel Operating Statistics (5441)

V. Other Energy Schedules (5500's)

Domestic and Foreign Statement of Income (5510)

VI. Nonenergy Schedule (5600's)

Domestic and Foreign Statement of Income (5610)

Appendix B

Selection of FRS Reporting Companies

Appendix B

Selection of FRS Reporting Companies

Twenty-seven companies were initially notified of a requirement to file Form EIA-28. This group was chosen from the top 50 publicly owned domestic crude oil producers in 1976 who had at least 1 percent of either the production or the reserves of oil, gas, coal, or uranium; or 1 percent of refining capacity or petroleum product sales.[1] The mergers of E. I. du Pont de Nemours and Company (Du Pont) with Conoco and U.S. Steel with Marathon Oil together with the selection criteria applied to 1982 data resulted in the following list of companies:

Amerada Hess Corporation
American Petrofina, Incorporated
Ashland Oil, Incorporated
Atlantic Richfield Company
Burlington Northern, Incorporated
Chevron Corporation (formerly Standard Oil of California)
Cities Service Oil Company[2]
Coastal Corporation
E. I. du Pont de Nemours and Company
Exxon Corporation[3]
Getty Oil Company[3]
Gulf Oil Corporation[3]
Kerr-McGee Corporation
Mobil Oil Corporation
Occidental Petroleum Corporation
Phillips Petroleum Company
Shell Oil Company
Standard Oil Company (an Indiana Corporation)
Standard Oil Company (an Ohio Corporation)
Sun Company, Incorporated
Superior Oil Company[3]
Tenneco, Incorporated
Texaco, Incorporated
Unocal Corporation (formerly Union Oil of California)
Union Pacific Corporation
United States Steel Corporation

Footnotes to Appendix B

[1]General Electric (GE) was originally included in the above group, because of its interest in Pathfinder Mines Corporation (Pathfinder), which was a uranium-producing company. However, GE did not ultimately file Form EIA-28, because Pathfinder's financial statements were not consolidated into the financial statements of GE as a FRS reporting company. Pathfinder was exclusively involved in uranium, which made it dissimilar to the other 26 companies; hence, Pathfinder was not included in the FRS database.

[2]Occidental Petroleum acquired Cities Service in 1982. However, Occidental Petroleum did not consolidate Cities Service's operations until December, 1982. Consequently, Form EIA-28 was filed for Cities Service for 1982 and this company is included as a separate company for 1982 and all prior years.

[3]In 1984, Chevron Corporation acquired Gulf Oil Corporation, Mobil Corporation acquired Superior Oil Company, and Texaco acquired Getty Oil Company. None of the acquisitions were consolidated for the entire year of 1984, and all acquired companies made financial reports for 1984. Consequently, Form EIA-28 was filed by all three acquired companies for 1984 and the three acquired companies are included as separate companies for 1984 and all prior years.

Appendix C

Data Quality Assurance Program

Appendix C

Data Quality Assurance Program

This data quality assurance program outlines EIA's efforts to insure the quality and integrity of FRS data. These efforts are evidenced in the design of the form, the mode of FRS staff operation, and in the procedures applied to checking the data, i.e., the desk audit and machine programmed checks.

Forms Design

The Securities and Exchange Commission (SEC) Form 10K contains financial statements certified by independent certified public accountants. These financial statements, and the entire text of the annual report and Form 10K, are reviewed by the SEC staff. With these procedures and requirements, the SEC's intention is to provide the investing public with assurances that data filed on Form 10K are accurate and are in accordance with generally accepted accounting principles.

In order to take advantage of the SEC review and the certification by Certified Puplic Accountants, the FRS Form EIA-28 is designed in a multitier structure, which presents both the Form 10K figures and statistics and the more detailed data required by FRS. The top level FRS tier corresponds to Form 10K; the second level tier is the first level disaggregated into the different sources of energy (e.g., petroleum, coal, nuclear, etc.); and the third level tier is the second level disaggregated into the specific functional line-of-business segments within each source of energy. (See Appendix A, which describes the FRS segments in detail.) The fourth level tier provides further detail within the individual segments, for example, the details of the patterns of petroleum raw materials purchased and sold. Therefore, the low level tiers can be aggregated to each successively higher tier until the consolidated Form 10K figures are reached. In this way, the more detailed FRS figures are locked into the figures already reported publicly.

Mode of Operation

The FRS staff attempts to facilitate the accurate filing of FRS data, by the reporting companies, in three ways:

1. The FRS staff is always readily accessible to any reporting company staff person with questions. For example, the staff has answered many questions from reporting company field personnel who have been filling out specialized areas of the form. This accessibility is important, considering the complexity of the form and the large number of people within each company involved in filling it out.

2. During the course of reviewing incoming forms and discussing reporting problems, deficiencies or clarifications are identified which should be made to the instructions and the glossary. Such changes are made periodically so that reporting companies always have the most up-to-date instructions and glossary available.

Comparison with Audited Information

The next area of the review procedures is considered the most important. This is the detailed comparison of the data submitted to FRS with that contained in the Form 10K report and the annual report to shareholders.

As stated previously, the Form 10K report and the annual report contain financial information that has been examined and reported by an independent certified public accountant. This financial information along with textual and statistical information has also been reviewed by the SEC staff, which includes not only accountants, lawyers, and financial analysts, but also petroleum and mineral resource engineers. Hence, the data contained in these documents are considered a valuable reference in connection with the quality of FRS data.

The data contained in each respondent's submission is compared to the Form 10K and the annual report material using a detailed audit program. Each audit program step is performed by trained auditors with accounting degrees, supervised by CPA's with experience, not only in auditing large public companies, but also with the SEC as former staff members.

These comparisons involve checking elements in both the financial and physical information areas (i.e., production, reserves, refinery statistics, etc.). Direct comparisons are made of specific data elements of the FRS form with corresponding items on Form 10K or in the annual report. Indirect comparisons deal with information that is mentioned in Form 10K and the annual report but which is not quantified sufficiently for direct matching with FRS data. For example, if a respondent's annual report discussed an investment in "tar sands," appropriate entries would be expected on the FRS schedule for tar sands.

Comparison Procedures

The FRS review procedures also include two other types of comparisons. The first type of comparison is made against prior year FRS data. These procedures assure consistency and reasonableness across reporting years.

The second type of review involves comparison to other related data series. Information contained in the FRS is compared to data available from other DOE systems and published data, such as State mining surveys.

The FRS review and audit procedures, described above, lead to the issuance of a set of questions to the reporting companies each year. Response to these questions generates substantial interchange between the energy company staffs and the FRS staff. From this interchange the company personnel have acquired a better understanding of the unique aspects of the FRS, and the FRS staff has learned more about each reporting company. Also achieved has been a greater understanding of reporting company accounting and reporting practices and how they might affect the published FRS aggregate data.

3. The FRS staff provides a detailed review of incoming forms, as soon as possible, after receipt. The section that follows outlines the content of this review.

Review Procedures

Detailed desk review and machine editing procedures have been established for the incoming FRS data. The end product of each review is the issuance of a letter to the reporting company containing questions regarding specific data elements. The reporting companies are instructed to respond to each question, either by explaining the item or by amending any incorrect schedule. When an amended schedule is received, it is reprocessed like the original with the full range of desk and machine checks. The result of this process is a relatively clean data base from which to compile the output reports.

The FRS review procedures include:

- Machine programmed checks for mathematical accuracy (e.g., addition and subtraction);
- Machine programmed checks to insure that corresponding schedules are correctly cross-referenced;
- Comparing reported FRS data to information from each company's Form 10K and annual report;
- Comparing reported data (e.g., average cost per foot drilled) for an individual FRS company to the average for all FRS reporting companies, to ascertain any variance; and
- Comparing reported data to other related data series to ascertain any unusual variances.

Machine Programmed Checks

The machine programmed checks for mathematical accuracy insure that each horizontal and vertical total equals the sum of the amounts within each line or column. These checks also ascertain that the amounts within a certain section of a schedule equal the amount of the same description within a different schedule. Thus, these checks insure the mathematical accuracy of the schedule.

Cross-referencing between schedules is performed through machine programmed checks. These checks are performed to insure accuracy and consistency between different schedules. For example, if a respondent indicated on Schedule 5210 that the Domestic Production Segment charges for depreciation, depletion and amortization were a certain amount, a comparison would be made with schedule 5120 to ascertain that the amount reported on 5210 agreed with the amount on 5120. Approximately 75 of these checks are performed on each respondent's submission. Since the number of errors noted during these checks is an indicator of respondent misunderstanding of the form, existing and potential problems are identified. The FRS review staff can then focus most of their attention on specific areas where data accuracy may be more of a problem.

Appendix D

Financial Analysis Guide

Appendix D

Financial
Analysis
Guide

Appendix D

Financial Analysis Guide

This appendix describes some analytical topics and issues. A familiarity with these topics and issues is very helpful, and sometimes essential, in using the FRS data.

Indicators of Financial Performance

To depict the activities of the FRS companies classified by the various energy industries, several indicators have been selected which are designed to show the dollar values and geographic distribution of production, profits, funds generated, accumulated investment, and annual new investment. These indicators are compared across segments, across functions within segments, and geographically. They are the same, or similar, to indicators which have been in regular use by financial analysts and economists for many years. However, to avoid potential misunderstandings, a discussion follows of the measures used, their significance, and their limitations.

All of these measures are based upon the existing framework of financial reporting now used by industry, which relies on "generally accepted accounting principles" (GAAP). GAAP is the set of accounting principles by which industry reflects the financial results of operations and the accumulated assets, liabilities, and owners' equity of individual business enterprises. The two primary problems one must contend with in using present GAAP-based data is that not all companies use the same GAAP accounting methods (e.g., full cost versus successful efforts in petroleum) and GAAP is based upon historical cost accounting principles (inflationary distortions are not reflected). Both of these can cause a degree of noncomparability of reported data, across companies in the case of accounting methods, and through time in the case of historical cost accounting. In spite of these problems, the data are still regarded as meaningful, especially for trend analysis. (For a further discussion of these two problems see Appendix E.)

The financial measure of the production and distribution of raw materials and refined products is operating revenues, or sales. Under GAAP this measure is based on arms-length transactions with third parties. However, in FRS the concept of sales has been extended to include sales from one segment to another. In such an approach, one segment's sales become another segment's costs, which must be eliminated in consolidation. The establishment of the FRS line-of-business segments, the definition of sales (trading function), and the necessary categories of nontraceable and eliminations are discussed more fully in Appendix E.

Profits are the measure of financial return for company activities. In FRS, profits are expressed in terms of net income, operating income, and contribution to net income. The first term applies only to the consolidated company profits, and is used after the deduction for income tax expense. Operating income applies both to the segments and to the consolidated company and is the net of operating revenues and operating expenses. Excluded from this figure are such items as income taxes, and interest income and expense. Interest expense is not allocated to the segments because it is a "corporate level" item for FRS purposes. (This

is explained more fully in Appendix E.) Contribution to net income is meant to be the equivalent of net income for individual segments. The term net income is not used for individual segment since, several corporate level items are not allocated to the segment level.

Funds from operations are presented for the consolidated company. It is intended to be conceptually close to "cash generated from operations." This is calculated by taking net income, or contribution to net income, and adding back the noncash components of net income, such as depreciation, depletion, amortization, and deferred taxes. It is a useful concept in judging the amount of resources, in the short run, that a corporation is generating from its operations. This is useful not only in judging solvency, but in ascertaining which resources are available for new investment. It seemed useful as an adjunct to net income, because it is quite possible for a company or industry, which is generating huge net losses, to have a positive funds flow. In the long run, however, net income is the best measure of resources generated from operations.

Accumulated investment is expressed by: (1) total assets, (2) net property, plant, and equipment (PP&E), (3) investments and advances to unconsolidated affiliates, and (4) net investment in place.

Total assets is used in the context of the consolidated company figures, and is the total of the left-hand, or asset side of the balance sheet.

Net PP&E is frequently used as a measure of resources committed by an enterprise to an industry or segment. In the energy industry, net PP&E accounts for the bulk of the consolidated assets.

Investments and advances to unconsolidated affiliates is of interest because many energy companies extend the range of their activities through subsidiaries which are less than 50 percent owned.

Finally, net investment in place is the total of: (1) net PP&E, and (2) investments and advances to unconsolidated affiliates.

Annual new investment is the measure of newly committed resources during any given year. In the FRS, this is expressed in terms of: (1) additions to PP&E; (2) current capitalized exploration and development (E&D) expenditures; (3) current expenditures on E&D; (4) additions to investment in unconsolidated affiliates; and (5) additions to net investment in place. The key words are: current, which means the current reporting year; expenditures, which means simply the cash expended; and capitalized, which refers to the portion of total annual expenditures which are classified as an addition to the PP&E account in the balance sheet instead of being classified as an expense of the current year in the income statement. Being capitalized usually implies that the expenditure benefits future years and will be amortized to expense in the years benefited. Being expensed implies the benefit is to the current year, and therefore the item should be shown as an expense of generating that year's revenues. The capitalization concept is at the heart of the difference between the successful efforts versus full cost accounting methods (discussed in Appendix E). Therefore, in FRS, total expenditures that are both expensed and capitalized are used as a measure of activity in order to obviate the effect of differing accounting methods in the context of measuring the deployment of new resources.

Reserve Interests (Foreign)

This category includes all three categories of foreign reserves collected on the FRS form: (1) net ownership interest reserves; (2) proportionate interest in investee reserves and (3) foreign access reserves. These three foreign categories are added together for purposes of comparison with domestic net working interest reserves because of the different nature of company interests in foreign production as compared to domestic.

Foreign petroleum reserve statistics are not strictly comparable to U.S. petroleum reserves because of the more complex and varying arrangements whereby companies obtain foreign crude. In addition, such arrangements have been known to be changed suddenly by the host governments, thereby imposing a degree of uncertainty about what a reporting company can describe as their equity reserves. Foreign reserve statistics may be used as an indicator of the rate and magnitude of industry activity, but their different character from U.S. reserves must be recognized.

Appendix E
Accounting Practices

READEX FICHE best copy available

Appendix E

Accounting Practices

This appendix describes some of the more important accounting topics and issues. A familiarity with topics and issues is very helpful, and sometimes essential, in using the FRS data.

Relation of FRS to Generally Accepted Accounting Principles

In completing the FRS form, with one exception noted below, companies use the same generally accepted accounting principles that they use in their financial statements filed with the Securities and Exchange Commission and in their annual report to shareholders. Therefore, the amount and timing of income recognized and the capitalization policies will be the same, and net income in FRS will agree in total with that reported in each company's public financial statements.

However, in FRS the presentation of the details of financial and statistical data will usually differ somewhat from that presented by most individual companies because current reporting standards do not require standardized functional line-of-business segments with standardized financial statement line items. In FRS, such standardization is necessary because of the aggregation of a large number of companies. Subsequent sections of this appendix discuss some of the conventions adopted by the FRS.

FRS Petroleum Supply and Trading Function

In establishing the FRS functional lines of business for reporting the activities of vertically integrated enterprises, it was necessary to define a set of trading rules. These rules define which segment can sell what to whom. Otherwise, the segment data would be inconsistent across companies.

FRS defines the following segments within petroleum (These segments are the main components of the 5200 series schedules.)

Domestic Production
Domestic Refining/Marketing
Rate Regulated Pipelines
Foreign Production
Foreign Refining/Marketing
International Marine (Transportation)

A few of the more noteworthy rules are as follows:

1. Transfers (sales) between segments of the same company are recorded at the equivalent of arm's-length market prices. Where there are no comparable arm's-length transactions, field posted prices may be used. If third party realizations for specific raw material streams are below posted prices, the same lower prices should be used to value internal movements of those raw materials.

2. All crude produced is recorded as a sale by the respective Foreign or Domestic Production segments to the corresponding Foreign or Domestic Refining/Marketing segments. The production segments are not permitted

to sell crude directly to third parties but instead transfer it to the company's refining/marketing segments which then make the sale to the third parties. Companies that do not have foreign refining and import all foreign purchase may deviate from this practice and sell directly to domestic refining/marketing.

3. Crude purchase from third parties is reflected as a purchase by the appropriate refining/marketing segment: Foreign Refining/Marketing for foreign source crude and Domestic Refining/Marketing for domestic source crude. Foreign source crude destined for a U.S. refining segment is then recorded as a sale by the Foreign Refining/Marketing segment to the Domestic Refining/Marking segment.

4. Although production segments are neither sellers to, nor purchasers of, crude from third parties by FRS convention, natural gas may be both purchased and sold by production segments.

5. All transportation costs are incurred by the purchasing segment. Therefore, when Domestic Refining/Marketing purchases crude from Foreign Refining/Marketing, the Domestic Refining/Marketing segment incurs the cost of transport.

6. With regard to sales to third parties, an export sale is a sale shipped free on board (f.o.b.) destination to a foreign location. In contrast, if a sale is made f.o.b. to a domestic location, it is considered a domestic sale even though the goods may ultimately be shipped overseas by a third party who purchased the goods.

7. A domestic purchase is a purchase made from domestic sources, even though in the case of goods purchased from domestic third parties, the materials purchased may be of foreign origin. Such purchases are designated as domestic in FRS, because the point of purchase, and not the country of production, is the determining factor.

The above rules are intended to make the trading patterns of each FRS reporting company comparable to those of the other companies.

Nontraceables and Eliminations

One of the objectives of the FRS is to allow economic and financial analysis of the energy industry to be performed, as much as possible, by function. These functions, referred to in FRS as "segments," are intended for presentation as separate entities with their own income statements. They will reflect sales and purchases not only to and from unaffiliated parties, but also to and from other segments. Because the segments are, in actual fact, not separate entities, but are part of an integrated firm, two special classifications are defined which allow reconciliation of consolidated company figures with those of the segments. The first is the nontraceable classification, which covers those items included in the consolidated financial statements but not allocated to the segments. The

second is the eliminations classification, which is necessary to prevent double counting of intersegment transactions when the segments are consolidated into total company figures.

The purpose of the nontraceable classifications is to capture assets, liabilities, revenues, and expense items, etc., which exist only in the corporate context and cannot reasonably be attributed to the activities of a segment. In the FRS data, this classification reflects general overhead for the consolidated firm and financial transactions which represent corporate level activities. It should be noted that the financial transactions may play a key role in the firm's ability to do business, but because of their fungible nature, such transactions are not allocated to activities in a single segment. The cash and investment accounts in the balance sheet, and the interest income and expense accounts in the income statement, are the best examples of this. The accompanying example illustrates a nontraceable item, interest expense of $20, and the $10 corresponding tax effect (see "FRS Segment Tax Allocation Rules" in this appendix for further explanation).

The need for the eliminations classification arises when the product of one segment is sold to a second segment, which in turn sells the product again. In the accompanying example, $80 of crude is sold by the Domestic Production segment of a petroleum company to the Domestic Refining/Marketing segment of the same company. The Refining/Marketing segment records $80 of purchases of crude and, after processing, reflects sales of $160 of refined product. If the segment figures were simply added to arrive at the consolidated total, the consolidated sales figure of $240 ($80 + $160) would be too high because of double counting. Thus, the eliminations classification is created to subtract $80 of sales and $80 of costs, leaving consolidated sales of $160, the appropriate measure of the firm's consolidated transactions.

The nontraceables and eliminations classifications are treated like pseudosegments for purposes of aggregating segment data to the consolidated level.

Example of Nontraceables and Eliminations:

	Consolidated	Elimination	Non-Traceable	Refining/Marketing	Production
Revenues	160	(80)	-	160	80
Less Expenses:					
General and Administrative	10	-	2	5	3
Other Operations	10	-	-	5	5
Crude	-	(80)	-	80	-
Operating Income	140	-	(2)	70	72
Less Interest Expense	20	-	20	-	-
Less Income Taxes	60	-	(11)	35	36
Net Income	60	-	(11)	35	36

Note: Numbers in parentheses are negative.

FRS Income Taxes

FRS Segment Tax Allocation Rules. In FRS, each segment reflects a pro-rata share of consolidated income taxes. Where the consolidated company has income and pays a tax, but an individual segment has a loss, the segment with a loss reflects a negative tax. This treatment is an FRS rule and its purpose is to reflect at the segment level the effect of the segment's operations on the consolidated taxes. The negative taxes, reflected at the segment level, are limited to that which the consolidated group can use. Thus, if the consolidated group has an overall loss and therefore cannot save any taxes through a particular segment's losses, that segment will not reflect any negative tax. Negative taxes at the segment level are recorded only to the extent that they offset positive taxes on a consolidated basis.

In comparing an FRS company segment to a specialized (nonintegrated) company in the same line of business, one must keep the above described rule in mind. The tax effect will be different, for a specialized company cannot actually pay a negative tax. It must carry the loss forward, or backward, against profits of other years, while a segment of an otherwise profitable consolidated firm can show a negative tax by FRS conventions since its loss can offset profits in other segments. Hence, it has a negative contribution to consolidated taxes.

FRS Reporting Companies, Segments, and Tax Paying Entities. This section explains how FRS reporting companies and their individual line-of-business segments differ from the entities which actually pay income taxes. The FRS is designed to report energy activities on a consolidated company basis, disaggregated into various energy lines of business. Accordingly, income tax expense, current and deferred, is reflected on a line-of-business basis. However, under the tax laws, taxes are not necessarily based upon FRS reporting company consolidated earnings, of the FRS line-of-business segments.

The tax-paying entities of an FRS reporting company are its subsidiaries. Some are incorporated in the United States and some in foreign countries, and each may operate in the United States, foreign countries, or both. Income tax expense in the FRS consists of both domestic and foreign income taxes incurred by these subsidiaries. Taxes reflected by the consolidated company and each individual segment are allocated from taxes paid and deferred by the actual tax-paying entities.

Under United States tax law, U.S. income taxes are not required to be paid by foreign corporations on their foreign operations. Only earnings of foreign corporations earned in the United States or paid into the United States as dividends to the U.S. parent corporation (owner) are taxed by the United States. Foreign and domestic earnings of U.S. corporations, including divisions and branch operations, are taxed by the United States. All income subject to U.S. tax, whether the entity is a foreign or domestic corporation, is given the benefit of the foreign income tax credit (up to the statutory rate) to avoid double taxation. Each U.S. incorporated subsidiary of a U.S. corporation elects to either be included in a consolidated U.S. tax return or to file a separate return, depending on which election is most likely to minimize the aggregate domestic and foreign taxes. The main point to be made here is that corporate organization and relationships are not purely a function of line-of-business financial reporting. This fact requires that allocations be made of taxes incurred so that they can be classified according to the FRS segment format.

These allocations are required when a subsidiary is involved in both U.S. and foreign operations and/or in more than one line of energy business. For example, the FRS has separate segments for the foreign and domestic chemical business, as it also does for the foreign and domestic refining/marketing business. Therefore, if an FRS reporting company has a foreign subsidiary involved in both refining/marketing of petroleum and chemicals, a disaggregation of that subsidiary's activities, including income taxes, must be performed.

The disaggregation is further complicated by the existence of nontraceable items such as interest. In making the tax allocation, the nontraceable column must be treated as a line-of-business segment. Therefore, interest expense, which is quite large for most companies, is classified in the nontraceable columns and, accordingly, should generate negative U.S. and foreign income taxes for the nontraceable segment.

In conclusion, an understanding of how taxes affect the operations of a particular line of business cannot be obtained simply by looking at the tax expense associated with an FRS segment. An indepth study of taxation of a line of business must consider the various available forms of corporate organization (the tax-paying entities) and the method of financing (interest expense).

Deferred Taxes

Under GAAP, there must be a matching of revenues with associated expense in the appropriate year. A firm's income statement, including pre-tax income, is calculated using GAAP. A firm's tax return, and hence income for tax return purposes (taxable income), is calculated based on the tax laws. The differences between GAAP and the tax laws regarding what and where to recognize income and expenses leads to one figure for taxable income and another for GAAP income. The difference may be broken down into: (1) timing differences and (2) permanent differences. Deferred taxes are provided in the financial statements to compensate for the timing differences. This is described more fully below.

An example of a timing difference is depreciation. Under GAAP the straight line method is often used for financial statement purposes, whereas for tax return purposes, an accelerated rate method is permitted by the tax laws. Under accelerated rates, more depreciation is taken in the earlier years of an asset's life than under the straight line method. This has the effect of showing a higher tax return depreciation during the earlier years of the asset's life. Hence, taxable income will be less than GAAP pre-tax income. The opposite relationship will be true during the final years of the asset's life, and hence, the timing difference "turns around."

In the context of the earlier years of the asset's life in the above example, a deferred tax expense is provided on the difference between the straight line and the accelerated rate depreciation figure. The income statement treatment for this is to reflect the amount actually payable to the Internal Revenue Service (IRS) that year as a "current tax" and the tax on the timing difference as a "deferred tax." Assuming all other factors of income tax are constant, in the final years of subject asset's life, the current taxes will be higher relative to the earlier years and the deferred taxes will be negative. Total tax expense

will be the same each year for the entire life of the asset, which is the objective of the deferred tax accounting rules.

Reflecting Ownership in Aramco

In 1980, the government of Saudi Arabia acquired a beneficial interest in substantially all of the assets and operations of Aramco. Aramco continues to have access to a significant volume of Saudi Arabia crude oil. As a consequence, the former Aramco partners no longer have a proportional ownership interest in Aramco reserves. However, the Aramco partners still maintain access to Saudi crude production through marketing agreements.

Prior to 1980, the equity method was used by all four FRS reporting companies in presenting their interest in the financial statements included in their annual reports to shareholders, although the details of the presentation differ somewhat from company to company. In the 1978 issue of Performance Profiles, the equity in Aramco earnings was reflected as a reduction in the cost of crude acquired by the Foreign Refining/Marketing segment. This had the effect of offsetting each company's Aramco earnings against their cost of crude acquired from Aramco at the prevailing purchase price.

In the 1979 issue of Performance Profiles, Aramco was reflected in the FRS on the equity method. That is, the investment and earnings from Aramco were reported on a one-line basis. Prior years were restated to this basis. Likewise, purchases of crude oil, production of crude oil, and interests in reserves were all reflected under the "unconsolidated affiliate" captions.

Corporate Acquisitions

The key topics in the section are: (1) the accounting for mergers -- purchase method versus pooling of interest method; (2) the portion of new investment attributable to transactions between FRS reporting companies; (3) accounting for internal growth versus growth by acquisition.

Under FRS reporting rules, no acquisitions are accounted for under the pooling of interest method. This is because under the pooling method, the financial statements do not reflect such transactions as new investment, since the historical financial statements are restated. One of the objectives of the FRS is to track new investment activities.

For FRS reporting purposes, acquisitions accounted for as poolings for annual report purposes must be reflected in the FRS filing under a modified purchase method. All purchase accounting rules are followed, except that the assets of the acquired company are not revalued, but are recorded at their book values as stated on the acquired company's books.

Therefore, the FRS balance sheet at year's end will agree with the reporting company's annual report, but the income statement will not. Activities of the acquired company are only reflected in the consolidated financial statements of the acquiring company for the period of time it is owned. Also, the balance

sheet accounts of the acquiring company as of the date of acquisition appear in the appropriate captions of the acquiring company's funds statement as sources and uses of funds, or working capital.

The growth of FRS reporting companies, like other industrial enterprises, is brought about by management both internally and through the acquisition of other enterprises and individual properties. The FRS schedules at this time do not attempt to distinguish growth through acquisition and merger from internal growth. New investment of funds are classified by line of business and functionally within each line of business. For example, all additional investment in producing petroleum properties are classified together, and are not separated according to whether a going corporation came with them or whether only the property was purchased.

Full Cost and Successful Efforts Accounting Methods

At this time, petroleum producing companies reporting to the Securities and Exchange Commission, which include all FRS reporting companies, are permitted to choose between two accounting methods--"full cost" and "successful efforts". The two methods differ from one another in the treatment of the cost of dry exploratory holes.

Under full cost, the cost of a dry exploratory hole is capitalized and then amortized to the income statement over the production life of successful wells, which is to say it is spread over many future years. Thus, the capitalized costs of both dry and successful wells are reflected in the balance sheet as part of producing properties.

Under successful efforts, the cost of a dry exploratory hole is written off to expense in the year drilling is determined to be unsuccessful. There is then no capitalized cost of such dry exploratory holes carried on the balance sheet.

In comparison to the successful efforts method, the full cost method will: (1) show less volatility of earnings, since the cost of unsuccessful wells is amortized over many years; (2) show a higher balance in accumulated property, plant, and equipment (PP&E), since the account contains the costs of all wells drilled, including dry exploratory wells; (3) usually show higher earnings during years of intense exploratory activity when a number of dry wells are encountered; and (4) show the same cumulative earnings over a long period of years, since eventually all costs will be amortized to the income statement. These effects are minimized if the firm is large, since the exploratory activities of a large firm are usually smaller relative to total production operations than they are in a small production firm.

Usually one cannot determine the precise effect of using one method over the other. However, one large firm switched from full cost to successful efforts in 1975 and restated 1973 and 1974 data to the successful efforts method. So we have available the impact of this conversion on their comparative net income, net PP&E, and return on net PP&E for 1973 and 1974 (see text table).

Years		Full Cost	Successful Efforts
1973			
	Net Income (dollars)	1,292,400	1,243,300
	Net PP&E (dollars)	8,476,700	7,511,300
	Net Income/PP&E (percent)	15.25	16.70
1974			
	Net Income (dollars)	1,586,400	1,544,700
	Net PP&E (dollars)	9,593,300	8,563,500
	Net Income/PP&E (percent)	16.54	17.98

Source: Texaco, Inc., 1974 and 1977 Annual Report and Statistical Supplements.

For the present group of FRS reporting companies, since they are among the largest petroleum companies, the incomparability problem does not seem likely to be severe.

Inventory Accounting—LIFO Versus FIFO

The Last In-First Out (LIFO) and the First In-Last Out (FIFO) inventory methods are most often used in the preparation of the financial statements of industrial enterprises.

Under FIFO, the balance sheet valuation of inventory is based upon the most recent prices paid for the physical units on hand at year's end, and the income statement reflects the cost of units sold at the oldest unit costs. In periods of rapidly rising prices, the income statement reflects higher profits than would be reflected if the units sold were priced at current replacement cost or under the LIFO method.

Under LIFO, the balance sheet valuation of inventory is based on the prices paid for the first units of each major type of inventory ever purchased. For example, crude oil could be carried at $3 per barrel, which of course vastly understates the value of the inventory in terms of its replacement cost. The income statement reflects the cost of units sold at the most recent prices paid for the number of units sold. Thus, cost of goods sold reflects nearly a replacement cost amount, and profits are lower than under the FIFO method.

Since either method is permitted under the Federal tax laws, most companies use LIFO for operations subject to U.S. taxation because earnings and hence taxes are lower than by using FIFO. By 1979, most FRS reporting companies were primarily using the LIFO inventory method. Most analysts probably would agree that LIFO is the preferable method, since the income statement is more realistic than with FIFO. However, its disadvantage is that the balance sheet's inventory figure is understated, and hence the stockholder's equity amount is correspondingly understated.

In 1984, 15 FRS companies reported liquidation profits, compared to 18 and 19 in 1983 and 1982, respectively. The 1984 aggregate liquidation profits increased the reporting companies' operating income by $1.5 billion, which represented 3 percent of their aggregate operating income. This compares to $2.3 billion in 1983 and $3.8 billion in 1982, which represented 5 percent and 9 percent of their respective aggregate operating income for those years.

Foreign Currency Translations

In December 1981, the Financial Accounting Standards Board (FASB) issued Statement No. 52, "Foreign Currency Translations," which superseded FASB-8, "Accounting for the Translation of Foreign Currency Transactions and Foreign Currency Financial Statements." FASB-52 covers the translation of the foreign currency financial statements for the purposes of the consolidation, combination, or reporting by the equity method, and the translation of foreign currency transactions. The new statement requires that assets, liabilities, and operations of an entity be stated in the currency of the primary economic environment in which the entity operates (termed, the "functional currency"). If a foreign entity has not kept its financial records in the functional currency, remeasurement is required prior to translation. Any gain or loss on remeasurement is recognized in current net income. The assets and liabilities of the foreign entity are translated from its functional currency to the reporting currency at the current rate of exchange.

Under FASB-52, gain or loss on the translation of foreign currency financial statements is shown as a separate component of stockholders' equity, whereas, under FASB-8, all non-monetary balance sheet items were translated at the historical rate of exchange. Thus, the change to FASB-52, which uses the current rate of exchange, had the most significant impact on inventories and fixed assets. With respect to the income statement, FASB-52 requires that only gains or losses from foreign currency transactions be included.

As the text table below indicates, foreign currency translation losses decreased stockholders' equity by 1 percent in 1984, and foreign currency transaction losses decreased pretax income by 0.1 percent.

Year	Translation Gains/Losses	Stockholders' Equity	Percent of Stockholders' Equity	Transaction Gains/Losses	Pretax Income	Percent of Pretax Income
	(million dollars)			(million dollars)		
1982	-1,764	183,933	-1.0	-111	45,157	-0.2
1983	-1,253	192,509	-0.7	35	47,420	0.1
1984	-1,683	176,461	-1.0	-44	47,609	-0.1

Appendix F

Statistical Disclosure Avoidance Procedures

Appendix F

Statistical Disclosure Avoidance Procedures

Appendix F

Statistical Disclosure Avoidance Procedures

During the development of this report, a systematic set of procedures that are intended to prevent the disclosure of "individually identifiable energy information" has been applied. Tables that appear in this report provide summary, rather than company, level information. In most cases, the level of summarization is for all FRS companies. In certain cases, subcategories have been established that break the reporters into size or other descriptive classes. Each table has been screened to insure that no statistical disclosure will occur.

A large number of summary computer reports, generated from a single selected data base, provide the basis for the tables that are published in this report. In conjunction with the summary reports, a parallel set of cell count reports were produced that tabulate for each report cell the number of nonzero values that were aggregated to produce the summary value. The cell count reports were then reviewed to identify whether potential disclosure problems would result from having an insufficient number of reporters or from having values that primarily represent dominant companies in a particular energy sector or activity.

If potential disclosure problems were identified, the tables were restructured to combine values or groups of individual cells in the tables so that the resultant tables were essentially disclosure free.

Appendix F

Appendix G

Detailed
Statistical
Tables

Appendix G

Detailed
Statistical
Tables

Table G1. Selected Domestic Operating Statistics for FRS Companies and Total Industry, 1983 and 1984

Operating Statistics	FRS Companies			Domestic Industry[1]			FRS as a Percent of Domestic Industry	
	1983	1984	Percent Change	1983	1984	Percent Change	1983	1984
Petroleum								
Net Production								
Crude Oil and Natural Gas Liquids (million barrels)	2,059.3	2,088.8	1.4	3,745.0	3,813.0	1.8	55.0	54.8
Natural Gas (billion cubic feet)	7,365.3	7,946.0	7.9	15,788.0	17,193.0	8.9	46.7	46.2
Net Imports								
Crude Oil and Natural Gas Liquids (million barrels)	818.7	876.2	7.0	1,386.2	1,447.7	4.4	59.1	60.5
Refinery Capacity (thousand barrels per day)	13,014.0	12,771.0	-1.9	16,773.0	16,325.0	-2.7	77.6	78.2
Refinery Output[2] (thousand barrels per day)	10,378.0	10,996.0	6.0	13,585.0	14,171.0	4.3	76.4	77.6
Bituminous Coal and Lignite								
Production (million tons)	185.2	226.0	22.0	778.0	891.8	14.6	23.8	25.3
Uranium								
Production[3] (million pounds)	6.6	4.1	-37.8	23.5	13.6	-42.1	28.3	30.4

[1]Domestic area defined to include the 50 states, District of Columbia, U.S. Virgin Islands, and Puerto Rico.
[2]For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.
[3]Mining production of uranium oxide (U308).

Note: The data for total U.S. production of crude oil and natural gas liquids and natural gas (dry) utilized in this report are taken from Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves (September 1985). This source is utilized in order to preserve consistency between production reported in the context of oil and gas reserves and reserve additions and production reported elsewhere in this report. However, the official Energy Information Administration U.S. totals for crude oil and natural gas plant production are 3,862.8 million barrels in 1984 and 3,759.1 million barrels in 1983 (see Energy Information Administration, Petroleum Supply Annual, 1984, Volume 1 (June 1985), P. 16). For dry natural gas production, the official Energy Information Administration U.S. totals are 17,231 billion cubic feet in 1984 and 16,033 billion cubic feet in 1983 (see Energy Information Administration, Natural Gas Monthly, August 1985, (October 1985), p.7).

Sources: Industry data -- Petroleum net production: Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves (September 1985). Net imports and refinery output: data compiled for the International Energy Agency by the Petroleum Supply Division, Office of Oil and Gas, Energy Information Administration. Refinery capacity: Energy Information Administration, Petroleum Supply Annual, 1983 and 1984. Coal production: Energy Information Administration, Weekly Coal Production, July 6, 1985. Uranium production: Energy Information Administration, Uranium Industry Annual 1984 (October 1985). FRS companies data -- Form EIA-28.

Table G2. A Comparison of Selected Financial Items for FRS Companies and the S&P 400, 1984 and Percent Change from 1983

Selected Financial Items	FRS Companies		S&P 400	
	1984 (billion dollars)	Percent Change from 1983	1984 (billion dollars)	Percent Change from 1983
Income Statement				
Operating Revenues	517.4	1.3	1,936.5	5.4
Operating Expenses	-467.3	1.0	-1,762.5	5.2
Operating Income	50.1	3.9	174.0	6.9
Other Income[1]	-2.7	224.2	-10.7	-49.8
Income Taxes	-26.1	2.6	-70.1	7.5
Net Income	21.3	-2.8	93.2	22.3
Sources of Funds				
Funds from Operations				
Net Income	21.3	-2.8	93.2	22.3
Other Funds from Operations[2]	42.3	9.2	93.2	-5.1
Subtotal	63.6	4.9	186.4	6.9
External Sources of Funds[3]	35.9	236.5	84.3	26.8
Other Sources of Funds	7.5	-21.6	66.8	-13.5
Total Sources of Funds	107.0	32.3	337.5	6.1
Uses of Funds				
Additions to PP&E	77.6	63.3	135.9	3.4
Dividends to Shareholders	11.9	0.9	40.8	-1.9
Other Uses of Funds	27.3	31.3	167.1	40.9
Total Uses of Funds	116.8	45.8	343.9	18.0
Increase (Decrease) in Working Capital	-9.8	(4)	-6.4	(4)

[1] 'Other Income' includes other revenue and expense, extraordinary items, and accounting changes.
[2] 'Other Funds from Operations' includes DD&A, deferred taxes, dry hole expense, recognized undistributed earnings/(losses) of unconsolidated affiliates, and minority interest.
[3] 'External Sources of Funds' includes proceeds from long term debt and equity security offerings.
[4] Not meaningful.
Source: Form EIA-28.

Table G3. Selected Financial Items for FRS Companies Ranked by Total Assets, 1984 and Percent Change from 1983

Selected Financial Items	All FRS		Top Third		Middle Third		Lower Third	
	1984 (billion dollars)	Percent Change from 1983	1984 (billion dollars)	Percent Change from 1983	1984 (billion dollars)	Percent Change from 1983	1984 (billion dollars)	Percent Change from 1983
Income Statement								
Operating Revenues	517.4	1.3	332.6	3.4	125.4	-1.2	59.4	-4.7
Operating Expenses	-467.3	1.0	-301.0	3.0	-111.6	-1.8	-54.7	-4.1
Operating Income	50.1	3.9	31.6	6.9	13.8	3.2	4.7	-11.0
Other Income[1]	-2.7	224.2	-0.2	-110.4	-1.5	-43.4	-0.9	343.8
Income Taxes	-26.1	2.6	-17.1	6.1	-6.9	4.8	-2.1	-23.9
Net Income	21.3	-2.8	14.3	-7.9	5.4	31.1	1.7	-28.1
Sources of Funds								
Funds from Operations								
Net Income	21.3	-2.8	14.3	-7.9	5.4	31.1	1.7	-28.1
Other Funds from Operations[2]	42.3	9.2	26.0	16.9	11.6	0.9	4.7	-6.3
Subtotal	63.6	4.8	40.3	6.8	16.9	8.9	6.4	-13.2
External Sources of Funds[3]	35.9	236.5	28.1	526.1	5.9	39.7	1.9	-3.7
Other Sources of Funds	7.5	-21.6	4.2	60.0	2.4	-58.8	0.9	-20.5
Total Sources of Funds	107.0	32.3	72.6	61.9	25.2	-1.4	9.2	-12.2
Uses of Funds								
Additions to PP&E	77.6	63.3	58.1	123.8	14.3	10.9	5.3	-39.4
Dividends to Shareholders	11.9	0.9	8.3	6.4	2.9	-8.0	0.7	-17.7
Other Uses of Funds	27.3	31.3	14.1	41.0	10.3	15.0	2.8	57.4
Total Uses of Funds	116.8	45.8	80.5	83.9	27.5	9.9	8.8	-22.3
Increase (Decrease) in Working Capital	-9.8	([4])	-7.9	([4])	-2.4	([4])	0.5	([4])

[1]'Other Income' includes other revenue and expense, extraordinary items, and accounting changes.
[2]'Other Funds from Operations' includes DD&A, deferred taxes, dry hole expense, recognized undistributed (earnings)/losses of unconsolidated affiliates, and minority interest.
[3]'External Sources of Funds' includes proceeds from long-term debt and equity security offerings.
[4]Not meaningful.
Source: Form EIA-28.

Table G4. A Comparison of Balance Sheet Items for FRS Companies and the S&P 400, 1984 and Percent Change from 1983

Balance Sheet Items	FRS Companies		S&P 400	
	1984 (billion dollars)	Percent Change from 1983	1984 (billion dollars)	Percent Change from 1983
Assets				
Current Assets	101.0	-9.2	640.0	6.8
Noncurrent Assets				
Property, Plant, and Equipment				
Gross	453.4	3.0	1,171.0	-5.2
Accumulated DD&A	-161.0	-0.5	-467.0	0.0
Net	292.4	5.0	703.0	-8.5
Investments and Advances	16.7	-6.8	86.0	21.1
Other Noncurrent Assets	12.8	-9.6	164.0	18.0
Subtotal Noncurrent Assets	322.0	3.7	953.0	-2.7
Total Assets	422.9	0.3	1,593.0	0.9
Liabilities and Stockholders' Equity				
Liabilities				
Current Liabilities	91.0	-0.0	440.0	11.1
Long-Term Debt	87.3	30.1	271.0	-2.2
Other Long-Term Items	66.0	-3.2	191.0	0.5
Minority Interest	2.2	-26.4	7.0	-22.2
Subtotal Liabilities and Other Items	246.5	7.5	910.0	4.2
Stockholders' Equity				
Retained Earnings	154.6	-4.2	522.0	1.0
Other Equity	21.9	-29.6	160.0	-14.9
Subtotal Stockholders' Equity	176.5	-8.3	682.0	-3.3
Total Liabilities and Stockholders' Equity	422.9	0.3	1,593.0	0.9

Source: Form EIA-28.

Table G5. Balance Sheet Items for FRS Companies Ranked by Total Assets, 1984 and Percent Change from 1983

Balance Sheet Items	All FRS		Top Third		Middle Third		Lower Third	
	1984 (billion dollars)	Percent Change from 1983	1984 (billion dollars)	Percent Change from 1983	1984 (billion dollars)	Percent Change from 1983	1984 (billion dollars)	Percent Change from 1983
Assets								
Current Assets	101.0	-9.2	66.9	-4.1	23.1	-16.4	11.0	-20.9
Noncurrent Assets								
Property, Plant, & Equipment								
Gross	453.4	3.0	294.5	18.1	114.3	-12.8	44.7	-25.4
Accumulated DD&A	-161.0	-0.5	-104.8	13.3	-39.4	-15.3	-16.8	-26.2
Net	292.4	5.0	189.7	21.0	74.9	-11.5	27.9	-24.9
Investments & Advances	16.7	-6.8	11.1	5.9	4.9	-8.1	0.6	-69.3
Other Noncurrent Assets	12.8	-9.6	7.3	-7.8	4.2	-9.2	1.4	-19.0
Subtotal Noncurrent Assets	322.0	3.7	208.1	18.8	84.0	-11.2	29.8	-26.9
Total Assets	422.9	0.3	275.0	12.3	107.1	-12.3	40.8	-25.4
Liabilities and Stockholders' Equity								
Liabilities								
Current Liabilities	91.0	-0.0	58.8	8.5	22.8	-8.4	9.4	-21.4
Long-Term Debt	87.3	30.1	53.5	85.5	25.4	-8.5	8.3	-20.5
Other Long-Term Items	66.0	-3.2	42.8	2.2	17.2	-6.0	6.0	-25.0
Minority Interest	2.2	-26.4	1.7	4.2	0.4	-67.9	0.2	-35.4
Subtotal Liabilities	246.5	7.5	156.8	23.9	65.8	-8.8	23.8	-22.1
Stockholders' Equity								
Retained Earnings	154.6	-4.2	111.3	6.2	29.3	-19.0	14.0	-31.6
Other Equity	21.9	-29.6	6.9	-49.3	12.0	-13.7	3.0	-17.5
Subtotal Stockholders' Equity	176.5	-8.3	118.2	-0.2	41.3	-17.5	17.0	-29.5
Total Liabilities and Stockholders' Equity	422.9	0.3	275.0	12.3	107.1	-12.3	40.8	-25.4

Source: Form EIA-28.

Table G6. A Comparison of Key Financial Indicators, Selected Performance Measures, and Patterns of Finance for FRS Companies and the S&P 400, 1982 to 1984

(Percent)

Financial Indicators	FRS Companies			S&P 400		
	1982	1983	1984	1982	1983	1984
Profit Measures						
Net Income to Total Assets	5.2	5.2	5.0	4.7	4.8	5.8
Net Income to Stockholders' Equity	11.9	11.4	12.1	10.6	10.8	14.3
Net Income to Net Investment in Place	7.7	7.4	6.9	8.6	9.1	11.8
Net Income Plus Interest to Total Invested Capital	11.9	11.5	12.0	12.1	12.0	14.3
Funds Flow Measures						
Funds from Operations to Total Assets	14.7	14.4	15.0	10.8	11.0	11.7
Funds from Operations to Total Sources of Funds	58.4	75.0	59.5	54.4	54.8	55.2
Additions to PP&E to Funds from Operations	118.3	78.4	122.0	94.6	75.3	72.9
Additions to PP&E to Total Sources of Funds	69.1	58.8	72.6	51.5	41.3	40.3
Dividends to Total Sources of Funds	11.0	14.6	11.1	13.1	13.1	12.1
Leverage Measures						
Long-Term Debt to Stockholders' Equity	37.1	34.8	49.5	42.1	39.3	39.7
Long-Term Debt to Total Assets	16.6	15.9	20.6	18.7	17.6	17.0

Source: Form EIA-28.

Table G7. Financial Indicators for FRS Companies Ranked by Total Assets, 1984
(Percent)

Financial Indicators	All FRS	Top Third	Middle Third	Lower Third
Profit Measures				
Net Income to Total Assets	5.0	5.2	5.0	4.1
Net Income to Stockholders' Equity	12.1	12.1	13.0	10.0
Net Income to Net Investment in Place	6.9	7.1	6.7	5.9
Net Income Plus Interest to Total Invested Capital	12.0	11.4	14.0	11.0
Funds Flow Measures				
Funds from Operations to Total Assets	15.0	14.6	15.8	15.8
Funds from Operations to Total Sources of Funds	59.5	55.5	67.3	69.6
Additions to Investment in Place to Funds from Operations	123.6	145.9	86.6	82.0
Additions to Investment in Place to Total Sources of Funds	73.5	80.9	58.2	57.1
Dividends to Total Sources of Funds	11.1	11.4	11.7	7.1
Leverage Measures				
Long-Term Debt to Stockholders' Equity	49.5	45.3	61.5	49.0
Long-Term Debt to Total Assets	20.6	19.5	23.7	20.4

Source: Form EIA-28.

Table G8. Distribution of Fixed Investment for FRS Companies, Domestic and Foreign, 1984

Fixed Investment	Consolidated Company	Domestic	Foreign	Eliminations and Nontraceables[1]
Net Investment in Place (billion dollars)				
Net Property, Plant, and Equipment	292.4	225.2	62.1	5.2
Investment and Advances to Unconsolidated Affiliates	16.7	6.8	7.8	2.1
Net Investment in Place	309.1	231.9	69.9	7.3
Net Investment in Place (percent distribution)				
Net Property, Plant, and Equipment	100.0	77.0	21.2	1.8
Investment and Advances to Unconsolidated Affiliates	100.0	40.4	46.7	12.8
Net Investment in Place	100.0	75.0	22.6	2.4
Additions to Investment in Place (billion dollars)				
Property, Plant, and Equipment	77.6	57.5	18.9	1.3
Investment and Advances to Unconsolidated Affiliates	0.6	0.7	0.2	-0.3
Net Investment in Place	78.2	58.2	19.1	0.9
Additions to Investment in Place (percent distribution)				
Property, Plant, and Equipment	100.0	74.0	24.4	1.6
Investment and Advances to Unconsolidated Affiliates	100.0	117.5	37.8	-55.3
Net Investment in Place	100.0	74.3	24.5	1.2

[1]Includes items in consolidated balance sheet that cannot be allocated to segments (nontraceables), and adjusts intersegment transfers for double counting (eliminations). In this table, this column is derived as a residual.

Source: Form EIA-28.

Table G9. Distribution of Selected Financial Items for FRS Companies Ranked by Total Assets, 1984

Selected Financial Items	All FRS (billion dollars)	Percent Distribution			
		All FRS	Top Third	Middle Third	Lower Third
Income Statement Items					
Operating Revenues	517.4	100.0	64.3	24.2	11.5
Operating Expenses	-467.3	100.0	64.4	23.9	11.7
Operating Income	50.1	100.0	63.1	27.5	9.4
Pretax Income	47.6	100.0	65.9	25.6	8.5
Net Income	21.3	100.0	66.9	25.1	7.9
Balance Sheet Items					
Net Property, Plant, and Equipment	292.4	100.0	64.9	25.6	9.5
Net Investment in Place	309.1	100.0	65.0	25.8	9.2
Total Assets	422.9	100.0	65.0	25.3	9.6
Sources and Uses of Funds					
Total Sources	107.0	100.0	67.9	23.5	8.6
Total Uses	116.8	100.0	68.9	23.6	7.5
Additions to PP&E	7.6	100.0	74.8	18.5	6.8
		(percent)			
Performance Indicators					
Net Income Plus Interest to Total Invested Capital		12.0	11.4	14.0	11.8
Percent Change in 1984 Net Income from 1983		-2.8	-7.9	31.1	-28.1
Percent Change in 1984 Additions to PP&E from 1983		63.3	123.8	10.9	-39.4
Percent Change in 1984 Total Assets from 1983		0.3	12.3	-12.3	-25.4

Source: Form EIA-28.

Table G10. Effective Tax Rates for FRS Companies Ranked by Total Assets and S&P 400, 1984

Income and Tax Items	FRS Companies				S&P 400
	All FRS	Top Third	Middle Third	Lower Third	
Income Statement Items (billion dollars)					
Pretax Income[1]	47.6	31.4	12.2	4.0	162.8
Current Taxes	-21.5	-15.0	-5.3	-1.2	-59.1
Deferred Taxes	-4.6	-2.2	-1.7	-0.8	-11.1
Income after Taxes[1]	21.5	14.2	5.3	2.0	92.7
Effective Tax Rates					
Current Taxes to Pretax Income	0.451	0.477	0.431	0.308	0.363
Current Plus Deferred Taxes to Pretax Income	0.549	0.545	0.567	0.515	0.431

[1]Pretax income and income after taxes exclude extraordinary items and the cumulative effect of accounting changes. As a result, the difference between income after taxes and net income is ($ 0.2) billion.

Source: Form EIA-28.

Table G11. Worldwide Income Taxes for FRS Companies, 1983 and 1984

Geographic Sector	1983	1984	Percent Change from 1983	Income Taxes as a Percent of Pretax Income	
	Billion Dollars			1983	1984
Pretax Income[1]	47.4	47.6	0.4	100.0	100.0
Income Taxes					
U.S. Federal	7.3	7.4	1.6	15.3	15.5
U.S. State and Local	0.7	0.8	6.3	1.5	1.6
Foreign	17.5	18.0	2.8	36.9	37.8
Total	25.5	26.1	2.6	53.7	54.9
Current Income Taxes					
U.S. Federal	4.0	3.5	-13.0	8.5	7.4
U.S. State and Local	0.7	0.8	13.3	1.4	1.6
Foreign					
Canada	1.5	1.9	27.1	3.1	4.0
OECD Europe	5.8	6.2	6.8	12.3	13.1
Africa	4.4	4.1	-5.2	9.2	8.7
Middle East	1.8	1.8	5.0	3.7	3.9
Other Eastern Hemisphere	1.5	2.3	52.7	3.2	4.9
Other Western Hemisphere	0.9	0.8	-10.3	1.8	1.6
Subtotal	15.8	17.2	8.6	33.4	36.1
Total	20.5	21.5	4.6	43.3	45.1
Deferred Income Taxes					
U.S. Federal	3.2	3.9	19.9	6.8	8.1
U.S. State and Local	0.1	0.0	-80.5	0.1	0.0
Foreign	1.6	0.8	-53.4	3.5	1.6
Total	4.9	4.6	-5.7	10.4	9.8

[1]Includes minority interest in income; excludes extraordinary items and cumulative effect of accounting changes.
Source: Form EIA-28.

Table G12 U.S. Federal Income Taxes for FRS Companies, 1983 and 1984

U.S. Tax Determination	1983	1984	Percent Change from 1983	Percent of Net Income Before Taxes	
	Billion Dollars			1983	1984
Pretax Income[1] (worldwide)	47.4	47.6	0.4	100.0	100.0
Adjustments to Income					
Income Not Subject to U.S. Taxes	-5.5	-5.7	3.9	-11.7	-12.1
Deductions for Income Taxes Paid in Other Jurisdictions	-3.6	-3.6	-1.2	-7.7	-7.6
Taxable Income	38.3	38.3	0.0	80.7	80.4
Expected Tax Computed at U.S. Statutory Rate	17.6	17.6	0.0	37.1	37.0
Cause of Increase or Decrease in Taxes					
Statutory Depletion	-0.3	-0.3	-6.4	-0.6	-0.5
Foreign Tax Credits	-9.0	-9.1	1.4	-19.0	-19.2
Investment Tax Credits	-1.6	-1.6	-0.4	-3.4	-3.4
Other	0.6	0.8	38.8	1.2	1.6
U.S. Income Tax Expense on U.S. Taxable Income	7.3	7.4	1.6	15.3	15.5
Current	4.0	3.5	-13.0	8.5	7.4
Deferred	3.2	3.9	19.9	6.8	8.1

[1]Includes minority interest income; excludes extraordinary items and cumulative effect of accounting changes.
Source: Form EIA-28.

Table G13. Domestic Taxes Other Than Income Taxes for FRS Companies, 1984 and Percent Change from 1983

Domestic Taxes Other than Income Taxes	Total Domestic		Petroleum		Coal		Other[1]	
	1984 (million dollars)	Percent Change from 1983	1984 (million dollars)	Percent Change from 1983	1984 (million dollars)	Percent Change from 1983	1984 (million dollars)	Percent Change from 1983
Production Taxes	5,717.9	-17.0	5,717.9	-17.0	0.0	--	0.0	--
Windfall Profit Tax	3,658.5	3.0	3,491.4	3.3	125.5	-2.2	41.6	-7.5
Severance Taxes	247.8	-22.0	181.2	-30.1	56.5	5.0	10.1	125.1
Other Direct Production Taxes								
Total Production Taxes	9,624.1	-10.6	9,390.4	-10.8	182.1	-0.1	51.7	4.5
Import Duties	106.1	-9.1	92.6	-16.0	0.0	0.0	13.5	109.3
Sales, Use, and Property	2,937.3	3.8	2,143.4	7.6	88.8	6.2	705.1	-6.6
Payroll	2,286.9	-23.6	727.7	-46.6	91.8	3.1	1,467.5	-4.9
Other Taxes	703.4	-38.6	443.8	-49.9	60.1	55.5	199.5	-10.1
Total Taxes Paid (Other than Income Taxes)	15,657.8	-12.3	12,797.9	-14.0	422.7	7.4	2,437.2	-5.4
Excise Taxes Collected	10,349.0	14.5	10,230.4	14.5	ND	--	[2] 118.6	19.4

[1]Nuclear, Other Energy, and Nonenergy.
[2]Coal Combined with Other to prevent disclosure.
-- = Not Applicable.
ND = Not Disclosable.
Source: Form EIA-28.

Table G14. Contributions to Income and Investment by Lines of Business for FRS Companies, 1984 and Percent Change from 1983

Income and Investment	Consolidated	Petroleum	Coal	Nuclear	Other Energy	Non-Energy	Nontraceables and Eliminations
	(million dollars)						
1984							
Operating Revenues	517,430.2	426,671.8	5,825.4	616.4	1,153.0	99,973.6	-16,810.0
Operating Income	50,096.9	49,975.1	657.4	-150.2	-197.9	3,849.7	-4,037.2
Net Income	21,308.9	23,632.1	568.8	-78.9	-6.6	2,890.2	-5,696.8
Net Investment in Place[1]	309,135.4	227,717.1	9,212.4	559.0	4,062.0	60,290.4	7,294.7
Additions to Investment in Place	78,237.4	66,786.2	1,627.2	115.1	870.6	7,902.4	936.0
	(percent)						
Distribution, 1984							
Operating Revenues	100.0	82.5	1.1	0.1	0.2	19.3	([2])
Operating Income	100.0	99.8	1.3	-0.3	-0.4	7.7	([2])
Net Income[3]	100.0	87.5	2.1	-0.3	-0.0	10.7	([2])
Net Investment in Place[1]	100.0	73.7	3.0	0.2	1.3	19.5	([2])
Additions to Investment in Place	100.0	85.4	2.1	0.1	1.1	10.1	([2])
Change from 1983							
Operating Revenues	1.3	0.5	10.5	-23.1	-3.3	5.5	([2])
Operating Income	3.9	0.4	42.6	([2])	-14.2	150.8	([2])
Net Income	-2.8	-1.7	21.5	388.0	([2])	62.7	([2])
Net Investment in Place[1]	4.3	7.3	-2.1	-48.7	1.8	-3.0	([2])
Additions to Investment in Place	62.9	74.6	45.8	86.7	21.5	14.9	([2])

[1]Measured as net property, plant, and equipment (PP&E) plus investment and advances.
[2]Not meaningful.
[3]Distribution is based on net income allocated to lines-of-business.
Source: Form EIA-28.

Table G15. Contributions to Income and Investment Patterns in Nonenergy Segments for FRS Companies, 1984 and Percent Change from 1983

Income and Investment	Consolidated Nonenergy	Chemical	Other Nonenergy
	(million dollars)		
1984			
Operating Revenues	99,973.6	50,968.8	49,047.3
Operating Income	3,849.7	3,623.6	226.1
Contribution to Net Income	2,890.2	2,341.2	549.0
Net Property, Plant, and Equipment	53,379.5	20,072.9	33,306.6
Investments and Advances	6,910.8	1,624.6	5,286.3
Net Investment in Place[1]	60,290.4	21,697.5	38,592.9
Additions to Property, Plant, and Equipment	7,032.1	3,124.3	3,907.8
Additions to Investment in Place	7,902.4	3,297.3	4,605.0
	(percent)		
Distribution, 1984			
Operating Revenues	100.0	51.0	49.1
Operating Income	100.0	94.1	5.9
Contribution to Net Income	100.0	81.0	19.0
Net Property, Plant, and Equipment	100.0	37.6	62.4
Investments and Advances	100.0	23.5	76.5
Net Investment in Place[1]	100.0	36.0	64.0
Additions to Property, Plant, and Equipment	100.0	44.4	55.6
Additions to Investment in Place	100.0	41.7	58.3
Change from 1983			
Operating Revenues	5.5	5.6	5.4
Operating Income	150.8	94.3	(2)
Contribution to Net Income	62.7	54.4	111.6
Net Property, Plant, and Equipment	-2.6	-4.4	-1.6
Investments and Advances	-6.1	1.7	-8.3
Net Investment in Place[1]	-3.0	-3.9	-2.5
Additions to Property, Plant, and Equipment	8.7	23.6	-0.8
Additions to Investment in Place	14.9	15.8	14.3

[1]Measured as net property, plant, and equipment (PP&E) plus investments and advances.
[2]Not meaningful.
Source: Form EIA-28.

Table G16. Effective Income Tax Rates by Lines of Business for FRS Companies, 1984

Income and Tax Items	Consolidated	Petroleum	Coal	Nuclear	Other Energy	Nonenergy	Eliminations and Nontraceables[1]
Income Statement Items (million dollars)							
Operating Revenues	517,430.2	426,671.8	5,825.4	616.4	1,153.8	99,973.6	-16,810.8
Operating Income	50,096.9	49,975.1	657.4	-150.2	-197.9	3,849.7	-4,037.2
Pretax Income[2]	47,609.3	52,795.3	778.5	-152.5	-133.9	4,336.7	-10,014.8
Income Tax Expense[3]	26,114.8	29,163.1	209.7	-73.6	-127.4	1,324.6	-4,381.7
Income After Taxes[2]	21,494.6	23,632.1	568.8	-78.9	-6.6	3,012.2	-5,633.1
Effective Tax Rates							
Income Tax Expense to Pretax Income	0.549	0.552	0.269	(4)	(4)	0.305	(4)

[1]Includes items in consolidated accounts that cannot be allocated to segments (nontraceables), and adjusts intersegment transfers for double counting (eliminations). Nontraceables may generate contributions to pretax income and tax expenses or benefits that affect the tax posture of the consolidated entity.

[2]Pretax income and income after taxes exclude extraordinary items and the cumulative effect of accounting changes. As a result, the difference between income after taxes and net income is ($ 185.7) million.

[3]Negative tax expenses represent net tax benefits allocated to lines-of-business.

[4]Not meaningful.

Source: Form EIA-28.

Table G17. Income and Investment by Lines of Business for FRS Companies Ranked by Total Assets, 1984 and Percent Change from 1983

Income and Investment	Consolidated Company	Petroleum	Coal	Nuclear[1]	Other Energy[1]	Non-Energy
			(million dollars)			
1984						
Contribution to Net Income						
Top Third	14,264.6	15,983.4	282.2	20.3	-141.4	981.2
Middle Third	5,353.7	5,807.3	192.3	-63.3	140.8	1,235.8
Lower Third	1,690.6	1,841.5	94.3	-35.9	-6.0	674.0
Net Investment in Place[2]						
Top Third	200,843.4	158,892.5	5,762.4	223.7	1,500.9	29,792.5
Middle Third	79,808.6	51,095.0	2,701.8	1,572.2		22,325.9
Lower Third	28,483.4	17,729.6	748.2	1,324.2		8,171.9
Additions to Investment in Place						
Top Third	58,316.1	51,642.9	1,215.0	80.3	99.4	4,787.9
Middle Third	14,647.0	11,537.5	220.3	423.8		2,148.0
Lower Third	5,274.3	3,605.9	191.9	382.1		1,046.4
			(percent)			
Distribution, 1984						
Contribution to Net Income[3]						
Top Third	100.0	93.3	1.6	0.1	-0.8	5.7
Middle Third	100.0	79.4	2.6	-0.9	1.9	16.9
Lower Third	100.0	71.7	3.7	-1.4	-0.2	26.2
Net Investment in Place[2]						
Top Third	100.0	79.1	2.9	0.1	0.7	14.8
Middle Third	100.0	64.0	3.4	2.0		28.0
Lower Third	100.0	62.2	2.6	4.6		28.7
Additions to Investment in Place						
Top Third	100.0	88.6	2.1	0.1	0.2	8.1
Middle Third	100.0	78.8	1.5	2.9		14.7
Lower Third	100.0	68.4	3.6	7.2		19.8
Change from 1983						
Contribution to Net Income						
Top Third	-7.9	0.8	24.6	77.4	75.4	3.6
Middle Third	31.1	-4.4	2.7	67.5	40.3	414.4
Lower Third	-28.1	-13.2	73.6	[4]	[4]	14.5
Net Investment in Place[2]						
Top Third	20.1	25.5	16.4	31.2	-7.3	0.1
Middle Third	-11.3	-13.7	-25.5	-22.6		-2.3
Lower Third	-27.2	-33.0	-9.8	5.4		-14.7
Additions to Investment in Place						
Top Third	122.0	147.3	96.8	757.2	-47.1	22.7
Middle Third	11.8	14.6	-15.8	12.1		-1.8
Lower Third	-39.2	-50.6	-19.0	88.7		22.6

[1]Nuclear and Other Energy combined for the middle and lower third company groupings for net investment in place and additions to investment in place to prevent disclosure.
[2]Measured as net property, plant, and equipment (PP&E) plus investments and advances.
[3]Distribution is based on net income allocated to lines-of-business.
[4]Not meaningful.
Note: Components may not sum to consolidated total because of eliminations and nontraceables.
Source: Form EIA-28.

Table G18. Performance Indicators by Lines of Business for FRS Companies Ranked by Total Assets, 1982 to 1984

(Percent)

Performance Indicators	Consolidated	Petroleum	Coal	Nuclear	Other Energy	Nonenergy
Profit Rates[1]						
All FRS						
1984	8.9	10.4	6.2	-14.1	-0.2	4.8
1983	9.1	11.3	5.0	-1.5	1.0	2.9
1982	9.3	12.5	4.4	-4.7	-5.4	0.6
Top Third						
1984	8.7	10.1	4.9	9.1	-9.4	3.3
1983	10.4	12.5	4.6	6.7	-5.0	3.2
1982	9.8	12.7	4.4	-16.2	-14.2	-0.8
Middle Third						
1984	9.4	11.4	7.1	-33.4	10.2	5.5
1983	7.5	10.3	5.2	-6.2	7.0	1.1
1982	8.3	12.7	4.0	-4.3	-2.9	-0.7
Lower Third						
1984	9.2	10.4	12.6	-24.5	-0.5	8.2
1983	7.3	8.0	6.5	3.3	2.2	6.1
1982	9.4	10.6	6.6	2.2	6.2	6.7

[1]Measured as the ratio of net income contribution to net investment in place for lines-of-business. Consolidated profit rate excludes eliminations and nontreceables.

Source: Form EIA-28.

Table G19. Contributions to Income and Investment Patterns in Worldwide Petroleum for FRS Companies, 1984 and Percent Change from 1983

Income and Investment	Worldwide	Domestic	Foreign
	(million dollars)		
1984			
Operating Revenues[1]	426,671.8	255,916.6	202,781.4
Operating Income	49,975.1	26,589.1	23,388.2
Contribution to Net Income	23,632.1	15,841.3	7,791.9
Net Investment in Place[2]	227,717.1	169,283.9	58,433.1
Additions to Investment in Place	66,786.2	49,729.9	17,056.3
Current Expenditures[3]	76,031.2	55,683.2	20,347.9
		(percent)	
Distribution 1984			
Operating Revenues	100.0	60.0	47.5
Operating Income	100.0	53.2	46.8
Contribution to Net Income	100.0	67.0	33.0
Net Investment in Place[2]	100.0	74.3	25.7
Additions to Investment in Place	100.0	74.5	25.5
Current Expenditures[3]	100.0	73.2	26.8
Change from 1983			
Operating Revenues	0.5	1.9	-1.1
Operating Income	0.4	-2.3	3.7
Contribution to Net Income	-1.7	-0.3	-4.5
Net Investment in Place[2]	7.3	9.7	0.9
Additions to Investment in Place	74.6	70.5	87.7
Current Expenditures[3]	62.6	61.8	64.8

[1]Worldwide total includes eliminations and nontraceables of -32,026.2
[2]Measured as net property, plant, and equipment plus investments and advances.
[3]Sum of additions to investment in place and exploration and development expenses.
Note: Sum of components may not equal total due to independent rounding, eliminations, and nontraceables
Source: Form EIA-28.

Table G20. Income and Investment Patterns in Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1984 and Percent Change from 1983

Income and Investment	Worldwide	Domestic	Foreign
	(million dollars)		
1984			
Contribution to Net Income			
Top Four	9,919.6	4,514.2	5,405.5
Five Through Twelve	10,023.4	8,364.0	1,659.5
All Other	3,689.1	2,963.2	727.0
Net Investment in Place[1]			
Top Four	8,864.6	67,595.4	40,469.2
Five Through Twelve	75,277.9	67,048.6	8,229.3
All Other	44,374.6	34,639.9	9,734.7
Additions to Investment in Place			
Top Four	41,703.1	28,788.3	12,914.8
Five Through Twelve	15,674.0	13,336.2	2,337.8
All Other	9,409.1	7,605.4	1,803.7
	(percent)		
Distribution, 1984			
Contribution to Net Income			
Top Four	100.0	45.5	54.5
Five Through Twelve	100.0	83.4	16.6
All Other	100.0	80.3	19.7
Net Investment in Place[1]			
Top Four	100.0	62.6	37.4
Five Through Twelve	100.0	89.1	10.9
All Other	100.0	78.1	21.9
Additions to Investment in Place			
Top Four	100.0	69.0	31.0
Five Through Twelve	100.0	85.1	14.9
All Other	100.0	80.8	19.2
Change from 1983			
Contribution to Net Income			
Top Four	0.4	3.7	-2.2
Five Through Twelve	-1.9	-1.5	-3.5
All Other	-6.6	-2.5	-20.3
Net Investment in Place[1]			
Top Four	35.5	47.8	19.0
Five Through Twelve	-8.6	-4.0	-34.3
All Other	-11.4	-10.6	-14.2
Additions to Investment in Place			
Top Four	227.3	235.9	209.7
Five Through Twelve	12.8	18.3	-10.7
All Other	-19.0	-18.3	-21.5

[1]Measured as net property, plant, and equipment plus investment and advances.
Note: Sum of components may not equal total due to independent rounding, eliminations, and nontraceables.
Source: Form EIA-28.

Table G21. Performance Indicators in Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1982 to 1984

(Percent)

Performance Indicators	Worldwide	Domestic	Foreign
Profit Rates[1]			
All FRS			
1984	10.4	9.4	13.3
1983	11.3	10.3	14.1
1982	12.5	12.7	11.8
Top Four			
1984	9.2	6.7	13.4
1983	12.4	9.5	16.2
1982	11.3	10.5	12.3
Five Through Twelve			
1984	13.3	12.5	20.2
1983	12.4	12.2	13.7
1982	14.9	14.9	14.8
All Other			
1984	8.3	8.6	7.5
1983	7.9	7.8	8.0
1982	10.2	11.3	6.8

[1]Measured as contribution to net income/net investment in place.
Source: Form EIA-28.

Table G22. Contributions to Income and Investment Patterns by Petroleum Segments for FRS Companies, 1984 and Percent Change from 1983

Income and Investment	Domestic				Foreign			
	Consolidated	Production	Refining/ Marketing	Pipelines	Consolidated	Production	Refining/ Marketing	International Marine
	(million dollars)							
1984								
Operating Revenues	[1] 255,916.6	76,867.9	220,658.5	14,931.9	[2] 202,781.4	43,837.0	193,259.3	2,220.0
Operating Income	26,589.1	23,473.4	-1,026.3	4,168.4	23,388.2	22,679.2	1,101.4	-404.2
Contribution to Net Income	15,841.3	13,256.4	104.8	2,497.0	7,791.9	7,457.2	716.3	-393.6
Net Property, Plant and Equipment	168,024.6	122,822.1	33,650.2	11,552.3	52,611.6	38,621.3	11,214.2	2,776.1
Net Investment in Place[3]	169,283.9	123,072.5	34,338.5	11,872.9	58,433.1	39,800.1	15,823.7	2,809.4
Additions to Property, Plant and Equipment	49,773.5	42,099.7	6,780.6	893.2	17,040.2	13,985.9	2,812.4	241.8
Additions to Investment in Place	49,729.9	42,099.4	6,763.8	866.6	17,056.3	13,999.6	2,813.0	243.7
	(percent)							
Distribution, 1984								
Operating Revenues	100.0	30.0	86.2	5.8	100.0	21.6	95.3	1.1
Operating Income	100.0	88.3	-3.9	15.7	100.0	97.0	4.7	-1.7
Contribution to Net Income	100.0	83.7	0.7	15.8	100.0	95.7	9.2	-5.1
Net Property, Plant and Equipment	100.0	73.1	20.0	6.9	100.0	73.4	21.3	5.3
Net Investment in Place[3]	100.0	72.7	20.3	7.0	100.0	68.1	27.1	4.8
Additions to Property, Plant and Equipment	100.0	84.6	13.6	1.8	100.0	82.1	16.5	1.4
Additions to Investment in Place	100.0	84.7	13.6	1.7	100.0	82.1	16.5	1.4
Change from 1983								
Operating Revenues	1.9	3.5	-1.4	38.4	-1.1	5.7	-1.9	-3.8
Operating Income	-2.3	5.7	(4)	19.0	3.7	7.6	-39.1	-12.1
Contribution to Net Income	-0.3	8.5	-93.6	24.0	-4.5	2.9	-45.7	-16.7
Net Property, Plant and Equipment	10.0	13.6	2.4	-1.3	1.4	7.5	-9.7	-21.4
Net Investment in Place[3]	9.7	13.5	1.5	-2.0	0.9	7.4	-8.3	-21.5
Additions to Property, Plant and Equipment	71.5	93.1	29.6	-55.3	85.1	88.2	62.8	402.0
Additions to Investment in Place	70.5	93.5	27.5	-58.8	87.7	93.1	57.6	366.9

[1]Includes eliminations and nontraceables of -36,534.9
[2]Includes eliminations and nontraceables of -56,541.9
[3]Measured as net property, plant, and equipment plus investments and advances.
[4]Not meaningful.
Note: Sum of components may not equal total due to independent rounding, eliminations, and nontraceables.
Source: Form EIA-28.

Table G23. Effective Income Tax Rates Within the Petroleum Segments for FRS Companies, 1984 and Percent Change from 1983

Income and Tax Items	Production		Refining/Marketing	
	1984 (million dollars)	Percent Change from 1983	1984 (million dollars)	Percent Change from 1983
Income Statement Items				
Worldwide				
Contribution to Pretax Income	48,241.5	6.6	631.6	-84.7
Income Taxes	-27,527.8	6.8	189.6	(1)
Domestic				
Contribution to Pretax Income	23,788.7	6.7	-666.4	(1)
Income Taxes	-10,532.3	4.5	771.2	(1)
Foreign				
Contribution to Pretax Income	24,452.7	6.5	1,298.0	-38.4
Income Taxes	-16,995.5	8.2	-581.6	-26.1
Effective Tax Rates (ratios - signs reversed)				
Worldwide				
Income Taxes/Contribution to Pretax Income	0.571		-0.300	
Domestic				
Income Taxes/Contribution to Pretax Income	0.443		1.157	
Foreign				
Income Taxes/Contribution to Pretax Income	0.695		0.448	

[1]Not meaningful.
Source: Form EIA-28.

Table G24. Income and Investment Patterns by Petroleum Segments for FRS Companies Ranked by Total Energy Assets, 1984 and Percent Change from 1983

Income and Investment	Domestic				Foreign			
	Consolidated	Production	Refining/ Marketing	Pipelines	Consolidated	Production	Refining/ Marketing	International Marine
	(million dollars)							
1984								
Contribution to Net Income								
Top Four	4,514.2	4,169.0	-253.6	612.7	5,405.5	5,212.0	509.5	-330.0
Five Through Twelve	8,364.0	6,795.8	322.6	1,244.8	1,659.5	1,607.5	108.4	-54.4
All Other	2,963.2	2,291.6	35.8	639.5	727.0	637.7	98.5	-9.2
Net Investment in Place[1]								
Top Four	67,595.4	50,015.7	15,024.2	2,555.5	40,469.2	23,649.8	14,383.4	2,435.9
Five Through Twelve	67,048.6	50,278.4	10,520.1	6,250.1	8,229.3	7,283.4	747.3	198.6
All Other	34,639.9	22,778.4	8,794.3	3,067.2	9,734.7	8,866.9	692.9	174.9
Additions to PP&E[2]								
Top Four	28,761.2	24,604.0	3,771.6	385.6	12,878.6	10,126.5	2,524.1	228.0
Five Through Twelve	13,391.7	11,220.5	1,812.6	358.5	2,347.9	2,128.4	210.0	9.5
All Other	7,620.7	6,275.2	1,196.4	149.1	1,813.7	1,731.0	78.3	4.3
	(percent)							
Distribution, 1984								
Contribution to Net Income								
Top Four	100.0	92.4	3.9	13.6	100.0	96.4	9.4	-6.1
Five Through Twelve	100.0	81.3	3.9	14.9	100.0	96.9	6.5	-3.3
All Other	100.0	77.3	1.2	21.6	100.0	87.7	13.6	-1.3
Net Investment in Place[1]								
Top Four	100.0	74.0	22.2	3.8	100.0	58.4	35.5	6.0
Five Through Twelve	100.0	75.0	15.7	9.3	100.0	88.5	9.1	2.4
All Other	100.0	65.8	25.4	8.9	100.0	91.1	7.1	1.8
Additions to PP&E[2]								
Top Four	100.0	85.5	13.1	1.3	100.0	78.6	19.6	1.8
Five Through Twelve	100.0	83.8	13.5	2.7	100.0	90.7	8.9	0.4
All Other	100.0	82.3	15.7	2.0	100.0	95.4	4.3	0.2
Change from 1983								
Contribution to Net Income								
Top Four	3.7	19.6	(3)	12.6	-2.2	11.2	-58.1	-14.4
Five Through Twelve	-1.5	8.7	-67.9	1.2	-3.5	-8.3	-268.6	-33.2
All Other	-2.5	-7.6	-88.9	166.8	-20.3	-20.9	-11.8	66.9
Net Investment in Place[1]								
Top Four	47.8	62.0	19.3	12.4	19.0	42.5	-1.4	-14.0
Five Through Twelve	-4.0	-2.4	-10.6	-4.7	-34.3	-28.0	-62.3	-53.9
All Other	-10.6	-12.5	-7.1	-6.4	-14.2	-14.3	1.7	-44.4
Additions to PP&E[2]								
Top Four	236.3	291.0	71.6	521.4	202.3	252.5	86.7	547.2
Five Through Twelve	18.8	18.8	14.1	50.1	-10.3	-7.0	-34.6	13.1
All Other	-17.2	3.5	-17.3	-91.2	-22.1	-23.7	43.9	-4.6

[1]Measured as net property, plant, and equipment plus investments and advances.
[2]Property, plant, and equipment.
[3]Not meaningful.
Note: Sum of components may not equal total due to independent rounding, eliminations, and nontraceables.
Source: Form EIA-28.

Table G25. Size Distribution of Income and Investment Within Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1982 to 1984
(Percent)

Patterns Across Size Groups	Worldwide			Domestic			Foreign		
	1982	1983	1984	1982	1983	1984	1982	1983	1984
Contribution to Net Income									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	34.8	41.1	42.0	24.5	27.4	28.5	62.9	67.7	69.4
Five Through Twelve	46.9	42.5	42.4	54.5	53.5	52.8	26.3	21.1	21.3
All Other	18.3	16.4	15.6	21.0	19.1	18.7	10.9	11.2	9.3
Net Investment in Place[1]									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	38.3	37.6	47.5	29.6	29.6	39.9	60.2	58.8	69.3
Five Through Twelve	39.3	38.8	33.1	46.7	45.2	39.6	20.9	21.6	14.1
All Other	22.4	23.6	19.5	23.7	25.1	20.5	19.0	19.6	16.7
Additions to Investment in Place									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	31.2	33.3	62.4	26.4	29.4	57.9	45.7	45.9	75.7
Five Through Twelve	36.3	36.3	23.5	41.0	38.7	26.8	22.1	28.8	13.7
All Other	32.5	30.4	14.1	32.6	29.6	15.3	32.2	25.3	10.6

[1]Measured as net property, plant, and equipment plus investments and advances.
Source: Form EIA-28.

Table G26. Performance Indicators by Petroleum Segments for FRS Companies Ranked by Total Energy Assets, 1982 to 1984

(Percent)

Performance Indicators	Domestic				Foreign			
	Consolidated	Production	Refining/ Marketing	Pipelines	Consolidated	Production	Refining/ Marketing	International Marine
Profit Rates[1]								
All FRS								
1984	9.4	10.8	0.3	21.0	13.3	18.7	4.5	-14.0
1983	10.3	11.3	4.8	16.6	14.1	19.6	7.7	-13.2
1982	12.7	14.8	6.0	20.8	11.8	17.4	4.7	-6.3
Top Four								
1984	6.7	8.3	-1.7	24.0	13.4	22.0	3.5	-13.5
1983	9.5	11.3	2.5	23.9	16.2	28.2	8.3	-13.6
1982	10.5	12.8	2.8	19.7	12.3	22.5	5.2	-6.2
Five Through Twelve								
1984	12.5	13.5	3.1	19.9	20.2	22.1	14.5	-27.4
1983	12.2	12.1	8.5	18.8	13.7	17.3	-0.5	-18.9
1982	14.9	14.9	10.6	21.8	14.8	19.2	0.6	-6.4
All Other								
1984	8.6	10.1	0.4	20.8	7.5	7.2	14.2	-5.3
1983	7.8	9.5	3.4	7.3	8.0	7.8	16.4	-1.8
1982	11.3	13.6	4.0	18.6	6.8	7.3	6.2	-6.5

[1]Measured as contribution to net income/net investment in place.
Source: Form EIA-28.

Table G27. Expenditures for Domestic and Foreign Petroleum for FRS Companies, 1983 and 1984

Petroleum Segment	Domestic Petroleum			Foreign Petroleum		
	Million Dollars			Million Dollars		
	1983	1984	Percent Change	1983	1984	Percent Change
Production Segment[1]						
Exploration	14,291.1	14,942.1	4.6	4,408.0	4,537.2	2.9
Development/Production	12,760.0	33,110.9	159.5	6,285.1	12,740.3	102.7
Total	27,051.1	48,053.0	77.6	10,693.1	17,277.6	61.6
Refining/Marketing Segment						
Refining	3,683.1	3,680.6	-0.1	(3)	(3)	(4)
Marketing	1,157.8	2,811.9	142.9	(3)	(3)	(4)
Transportation[2]	390.9	288.1	-26.3	(3)	(3)	(4)
Total	5,231.8	6,780.6	29.6	1,727.4	2,812.4	62.8
Transportation Segment						
Pipelines	1,996.6	893.2	-55.3	(4)	(4)	(4)
International Marine	(4)	(4)	(4)	48.2	241.8	402.0
Total	1,996.6	893.2	-55.3	48.2	241.8	402.0
Investments and Advances to Unconsolidated Affiliates	137.1	-43.6	(4)	-119.5	16.1	(4)
Total Current Expenditures	34,416.6	55,683.2	61.8	12,349.2	20,347.9	64.8

[1]Expenditures for exploration and development include all capitalized expenditures plus expenses associated with dry holes. Expenditures for all other segments are capitalized expenditures.
[2]Exclusive of rate regulated pipelines and international marine.
[3]Not available after 1980.
[4]Not meaningful.
Source: Form EIA-28.

Table G28. Petroleum Exploration and Development Expenditures for FRS Companies, Domestic and Foreign, 1984 and Percent Change from 1983

Exploration and Development Expenditures	Worldwide Expenditures	Domestic Expenditures			Foreign Expenditures		
	FRS Companies (million dollars) 1984	FRS Companies (million dollars) 1984	Percent Change from 1983	FRS Domestic as a Percent of Total FRS 1984	FRS Companies (million dollars) 1984	Percent Change from 1983	FRS Foreign as a Percent of Total FRS 1984
Exploration							
Acquisition of Unproved Acreage	6,874.8	5,666.4	-4.6	93.3	408.4	82.8	6.7
Geological and Geophysical	2,630.1	1,792.8	-6.2	68.2	837.3	1.9	31.8
Drilling and Equipping[1]	7,557.3	5,182.4	18.9	68.6	2,375.8	-6.6	31.4
Other[2]	3,217.8	2,300.5	10.7	71.5	916.5	11.8	28.5
Total Exploration	19,479.3	14,942.1	4.6	76.7	4,537.2	2.9	23.3
Development							
Acquisition of Proved Acreage	28,884.7	20,666.2	1547.2	73.8	7,338.5	3932.8	26.2
Lease Equipment	4,189.5	2,530.7	-6.1	60.4	1,658.7	8.7	39.6
Drilling and Equipping[1]	8,949.4	6,552.8	15.6	73.2	2,396.6	-16.7	26.8
Other[2]	4,707.7	3,361.2	6.9	71.4	1,346.6	-20.8	28.6
Total Development	45,851.3	33,110.9	159.5	72.2	12,740.3	102.7	27.8
Total Exploration and Development	65,330.6	48,053.0	77.6	73.6	17,277.6	61.6	26.4

[1]Expenditure incurred in a given year not cumulative (includes work in progress adjustment).
[2]Includes support equipment.
Source: Form EIA-28.

Table G29. Total Exploratory and Development Wells Drilled in the United States for FRS Companies and Domestic Industry, 1983 and 1984

Wells Drilled	Domestic Industry		FRS		All Other	
	1983	1984	1983	1984	1983	1984
Exploratory	9,940	11,090	973	1,214	8,967	9,876
Dry	3,710	3,790	747	887	2,963	2,903
Successful	2,080	2,290	452	545	1,628	1,745
Oil	1,630	1,500	295	342	1,335	1,158
Gas	13,640	14,880	1,720	2,101	11,930	12,779
Subtotal	27.2	25.5	43.4	42.2	24.8	22.7
Percent Successful						
Development	13,350	13,620	601	694	12,749	12,926
Dry	47,390	54,370	6,380	8,291	41,010	46,079
Successful	34,650	39,720	5,324	7,160	29,326	32,560
Oil	12,740	14,650	1,056	1,131	11,684	13,519
Gas	60,740	68,000	6,981	8,985	53,759	59,015
Subtotal	78.0	80.0	91.4	92.3	76.3	78.1
Percent Successful						
Total Wells Drilled	74,380	82,870	8,701	11,086	65,679	71,784

Note: Sum of components may not equal total due to independent rounding.
Sources: Industry data -- Special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information Administration's Monthly Energy Review, May 1985 (August 1985), p. 65. FRS companies data -- Form EIA-28.

Table G30. Domestic Exploration and Development Drilling and Equipping Costs for FRS Companies and Domestic Industry, 1983 and 1984

Costs and Wells	FRS Companies			Domestic Industry			FRS as a Percent of Domestic Industry	
	1983	1984	Percent Change	1983	1984	Percent Change	1983	1984
Exploration								
Cumulative Drilling and Equipping Costs (million dollars)[1]	4,752.1	4,461.8	-6.1	NA	NA	NA	NA	NA
Number of Wells Completed	1,720.7	2,101.1	22.1	13,640.0	14,880.0	9.1	12.6	14.1
Cost per Well Completed (thousand dollars)	2,762	2,124	-23.1	NA	NA	NA		
Development								
Cumulative Drilling and Equipping Costs (million dollars)[1]	4,973.5	5,323.3	7.0	NA	NA	NA	NA	NA
Number of Wells Completed	6,980.9	8,984.3	28.7	60,740.0	68,000.0	12.0	11.5	13.2
Cost per Well Completed (thousand dollars)	712	593	-16.8	NA	NA	NA		

[1]Excludes work in progress.
NA=Not available.
Sources: Industry data -- Special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information Administration's Monthly Energy Review, May 1985 (August 1985), p. 65. FRS companies -- Form EIA-28.

Table G31. Completed Well Costs, Oil, Gas, and Dry, for FRS Companies and Domestic Industry, 1983 and 1984

Drilling and Equipping Measures	FRS Companies			Domestic Industry			FRS as a Percent of Domestic Industry	
	1983	1984	Change	1983	1984	Change	1983	1984
Exploration								
Oil Wells								
Drilling and Equipping Costs[1]	723.6	809.1	11.8	NA	NA	NA	NA	NA
Wells Completed	452.4	545.4	20.6	2,080.0	2,290.0	10.1	21.8	23.8
Cost per Well (thousand dollars)	1,600	1,483	-7.3	NA	NA	NA	[2]	[2]
Average Depth (thousand feet)	8.1	8.1	0.4	5.0	5.3	6.0	[2]	[2]
Cost per Foot (dollars)	198.47	183.30	-7.6	NA	NA	NA	[2]	[2]
Gas Wells								
Drilling and Equipping Costs[1]	1,034.8	845.4	-18.3	NA	NA	NA	NA	NA
Wells Completed	295.3	342.0	15.8	1,630.0	1,500.0	-8.0	18.1	22.8
Cost per Well (thousand dollars)	3,504	2,472	-29.5	NA	NA	NA	[2]	[2]
Average Depth (thousand feet)	11.2	10.7	-4.3	6.2	6.3	1.6	[2]	[2]
Cost per Foot (dollars)	312.82	230.60	-26.3	NA	NA	NA	[2]	[2]
Dry Holes								
Drilling and Equipping Costs[1]	2,993.7	2,807.3	-6.2	NA	NA	NA	NA	NA
Wells Completed	973.0	1,213.7	24.7	9,940.0	11,090.0	11.6	9.8	10.9
Cost per Well (thousand dollars)	3,077	2,313	-24.8	NA	NA	NA	[2]	[2]
Average Depth (thousand feet)	9.1	8.9	-2.4	4.8	5.3	10.4	[2]	[2]
Cost per Foot (dollars)	336.59	259.19	-23.0	NA	NA	NA	[2]	[2]
Development								
Oil Wells								
Drilling and Equipping Costs[1]	2,800.8	3,299.9	17.8	NA	NA	NA	NA	NA
Wells Completed	5,323.9	7,159.5	34.5	34,650.0	39,720.0	14.6	15.4	18.0
Cost per Well (thousand dollars)	526	461	-12.4	NA	NA	NA	[2]	[2]
Average Depth (thousand feet)	4.8	4.4	-8.1	3.6	3.7	2.8	[2]	[2]
Cost per Foot (dollars)	109.31	104.25	-4.6	NA	NA	NA	[2]	[2]
Gas Wells								
Drilling and Equipping Costs[1]	1,732.2	1,623.7	-6.3	NA	NA	NA	NA	NA
Wells Completed	1,055.9	1,130.6	7.1	12,740.0	14,650.0	15.0	8.3	7.7
Cost per Well (thousand dollars)	1,641	1,436	-12.5	NA	NA	NA	[2]	[2]
Average Depth (thousand feet)	9.4	8.6	-8.0	5.2	5.2	0.0	[2]	[2]
Cost per Foot (dollars)	174.78	166.40	-4.8	NA	NA	NA	[2]	[2]
Dry Holes								
Drilling and Equipping Costs[1]	440.5	399.7	-9.3	NA	NA	NA	NA	NA
Wells Completed	601.1	694.2	15.5	13,350.0	13,620.0	2.0	4.5	5.1
Cost per Well (thousand dollars)	733	576	-21.4	NA	NA	NA	[2]	[2]
Average Depth (thousand feet)	7.4	6.9	-7.0	4.1	4.3	4.9	[2]	[2]
Cost per Foot (dollars)	99.10	83.75	-15.5	NA	NA	NA	[2]	[2]

[1]Million dollars.
[2]Not meaningful.
NA=Not available.
Sources: Industry data -- Special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information Administration's Monthly Energy Review, May 1985 (August 1985), p. 65. FRS companies data -- Form EIA-28.

Table G32. Completed Well Costs, Oil, Gas, and Dry, Onshore and Offshore, for FRS Companies, 1983 and 1984

Drilling and Equipping Measures	Total Domestic			Domestic Onshore			Domestic Offshore		
	1983	1984	Percent Change	1983	1984	Percent Change	1983	1984	Percent Change
Exploration									
Oil Wells									
Drilling and Equipping Costs[1]	723.6	809.1	11.8	422.5	371.3	-12.1	301.1	437.7	45.4
Wells Completed	452.4	545.4	20.6	390.2	474.8	21.7	62.2	70.6	13.5
Cost per Well (thousand dollars)	1,600	1,483	-7.3	1,083	782	-27.8	4,841	6,200	28.1
Average Depth (thousand feet)	8.1	8.1	0.4	7.7	7.7	0.6	10.5	10.7	1.1
Cost per Foot (dollars)	198.47	183.30	-7.6	141.27	101.41	-28.2	459.68	582.08	26.6
Gas Wells									
Drilling and Equipping Costs[1]	1,034.8	845.4	-18.3	619.6	455.6	-26.5	415.2	389.8	-6.1
Wells Completed	295.3	342.0	15.8	211.3	241.8	14.4	84.0	100.2	19.3
Cost per Well (thousand dollars)	3,504	2,472	-29.5	2,932	1,884	-35.7	4,943	3,890	-21.3
Average Depth (thousand feet)	11.2	10.7	-4.3	11.1	10.6	-4.5	11.4	10.9	-4.0
Cost per Foot (dollars)	312.82	230.60	-26.3	263.22	177.08	-32.7	435.21	356.59	-18.1
Dry Holes									
Drilling and Equipping Costs[1]	2,993.7	2,807.3	-6.2	1,312.5	1,243.4	-5.3	1,681.2	1,563.9	-7.0
Wells Completed	973.0	1,213.7	24.7	769.5	955.8	24.2	203.5	257.9	26.7
Cost per Well (thousand dollars)	3,077	2,313	-24.8	1,706	1,301	-23.7	8,261	6,064	-26.6
Average Depth (thousand feet)	9.1	8.9	-2.4	8.6	8.0	-7.4	11.1	12.4	11.7
Cost per Foot (dollars)	336.59	259.19	-23.0	197.99	163.08	-17.6	742.24	487.79	-34.3
Development									
Oil Wells									
Drilling and Equipping Costs[1]	2,800.8	3,299.9	17.8	2,091.3	2,471.6	18.2	709.4	828.3	16.8
Wells Completed	5,323.9	7,159.5	34.5	5,037.0	6,906.8	37.1	286.9	252.7	-11.9
Cost per Well (thousand dollars)	526	461	-12.4	415	358	-13.8	2,473	3,278	32.6
Average Depth (thousand feet)	4.8	4.4	-8.1	4.6	4.3	-6.6	9.2	8.8	-4.1
Cost per Foot (dollars)	109.31	104.25	-4.6	91.03	84.01	-7.7	268.11	370.78	38.3
Gas Wells									
Drilling and Equipping Costs[1]	1,732.2	1,623.7	-6.3	1,161.9	1,075.5	-7.4	570.3	548.2	-3.9
Wells Completed	1,055.9	1,130.6	7.1	941.6	1,009.1	7.2	114.3	121.5	6.3
Cost per Well (thousand dollars)	1,641	1,436	-12.5	1,234	1,066	-13.6	4,990	4,512	-9.6
Average Depth (thousand feet)	9.4	8.6	-8.1	9.1	8.4	-7.6	11.9	10.7	-10.6
Cost per Foot (dollars)	174.78	166.40	-4.8	135.94	127.12	-6.5	418.12	422.64	1.1
Dry Holes									
Drilling and Equipping Costs[1]	440.5	399.7	-9.3	330.6	276.8	-16.3	109.9	122.9	11.8
Wells Completed	601.1	694.2	15.5	566.4	641.0	13.2	34.7	53.2	53.3
Cost per Well (thousand dollars)	733	576	-21.4	584	432	-26.0	3,168	2,310	-27.1
Average Depth (thousand feet)	7.4	6.9	-7.0	7.2	6.8	-5.8	10.7	8.1	-24.4
Cost per Foot (dollars)	99.10	83.75	-15.5	81.16	63.75	-21.5	295.53	285.16	-3.5

[1]Million dollars.
Source: Form EIA-28.

Table G33. Exploratory Drilling and Equipping Expenditures and Numbers of Wells for FRS Companies and Domestic Industry, 1983 and 1984

Petroleum Acreage	Undeveloped Acreage		Developed Acreage		Total Acreage	
	Thousands of Acres	Percent Change from 1983	Thousands of Acres	Percent Change from 1983	Thousands of Acres	Percent Change from 1983
Onshore						
Top Four	42,345	12.5	10,213	14.2	52,558	12.8
Five Through Twelve	81,196	-19.8	11,510	-2.5	92,706	-18.0
All Other	35,457	-14.9	7,981	-14.5	43,438	-14.8
All FRS	158,998	-11.9	29,704	-1.3	188,702	-10.4
Offshore						
Top Four	5,792	33.1	1,653	44.2	7,445	35.4
Five Through Twelve	9,601	68.2	1,875	28.8	11,476	60.2
All Other	2,823	5.8	867	-14.5	3,690	0.2
All FRS	18,216	43.1	4,395	21.5	22,611	38.3
Total						
Top Four	48,137	14.6	11,866	17.6	60,003	15.2
Percent Onshore	88.0		86.1		87.6	
Five Through Twelve	90,797	-15.1	13,385	1.0	104,182	-13.3
Percent Onshore	89.4		86.0		89.0	
All Other	38,280	-13.6	8,848	-14.5	47,128	-13.8
Percent Onshore	92.6		90.2		92.2	
All FRS	177,214	-8.3	34,099	1.2	211,313	-6.9
Percent Onshore	89.7		87.1		89.3	
Industry					587,646	-0.8

Sources: Industry data -- Independent Petroleum Association of America, The Oil Producing Industry in Your State, 1985.
FRS companies data -- Form EIA-28.

Table G34. Domestic Reserve Additions, Exploration and Development Expenditures, and Expenditures per Barrel of Reserve Additions for FRS Companies Ranked by Total Energy Assets, and Domestic Industry, 1982 to 1984

Reserve Additions, Expenditures, and Wells	1982			1983			1984		
	Onshore	Offshore	Total	Onshore	Offshore	Total	Onshore	Offshore	Total
	(million barrels)								
Reserve Additions[1]									
Top Four	354.3	218.6	572.9	377.1	210.6	587.7	3,402.0	902.6	4,304.6
Five Through Twelve	547.0	394.9	942.0	701.5	240.8	942.3	295.9	210.4	506.3
All Other	224.6	116.8	341.4	880.2	219.6	1,099.8	1,271.3	56.4	1,327.7
All FRS	1,126.0	730.3	1,856.2	1,958.8	671.0	2,629.8	2,426.5	1,056.6	3,483.2
Domestic Industry	3,448.0	1,373.0	4,821.0	4,364.0	932.0	5,297.0	5,176.0	1,639.0	6,815.0
	(million dollars)								
Exploration and Development Expenditures									
Top Four	6,384.2	3,859.3	10,243.5	4,792.2	3,466.2	8,258.4	18,873.9	7,950.3	26,824.1
Five Through Twelve	12,627.4	5,036.3	17,663.7	7,434.6	5,266.7	12,701.4	9,501.6	5,183.4	14,685.0
All Other	8,145.7	3,027.2	11,172.9	3,773.9	2,317.5	6,091.3	3,704.0	2,839.8	6,543.9
All FRS	27,157.4	11,922.8	39,080.1	16,000.7	11,050.4	27,051.1	32,079.5	15,973.5	48,053.0
Domestic Industry	NA	NA	53,717.1	NA	NA	NA	NA	NA	NA
	(number of wells)								
Wells Completed									
Top Four	2,183.6	326.3	2,509.9	2,198.7	255.9	2,454.6	3,653.8	314.4	3,968.2
Five Through Twelve	3,988.3	375.8	4,364.1	3,660.2	340.8	4,001.0	4,696.9	373.0	5,069.9
All Other	2,480.5	241.1	2,721.6	2,057.1	188.9	2,246.0	1,878.6	168.7	2,047.3
All FRS	8,652.4	943.2	9,595.6	7,916.0	785.6	8,701.6	10,229.3	856.1	11,085.4
Domestic Industry	81,880.0	1,710.0	83,590.0	72,880.0	1,500.0	74,380.0	81,210.0	1,670.0	82,870.0
	(dollars per barrel)								
Exploration and Development Expenditures per Barrel of Reserve Additions									
Top Four	18.02	17.66	17.88	12.71	16.46	14.05	5.55	8.81	6.23
Five Through Twelve	23.08	12.75	18.75	10.60	21.88	13.48	32.12	24.63	29.01
All Other	36.26	25.93	32.73	4.29	10.55	5.54	2.91	50.35	4.93
All FRS	24.12	16.33	21.05	8.17	16.47	10.29	13.22	15.12	13.80
Domestic Industry	NA	NA	11.14	NA	NA	NA	NA	NA	NA
	(thousand barrels)								
Reserve Additions per Wells Completed									
Top Four	162.3	669.8	228.2	171.5	823.1	239.4	931.1	2,870.8	1,084.8
Five Through Twelve	137.2	1,050.9	215.8	191.7	706.5	235.5	63.0	564.1	99.9
All Other	90.6	484.3	125.4	427.9	1,162.4	489.7	676.7	334.4	648.5
All FRS	130.1	774.2	193.4	247.5	854.1	302.2	237.2	1,234.2	314.2
Domestic Industry	42.1	802.9	57.7	59.9	621.3	71.2	63.7	981.4	82.2

[1]Excludes revisions, includes crude oil and natural gas liquids (measured in millions of barrels) and natural gas (measured in millions of barrels of crude equivalent). Conversion factor for natural gas is .1769 barrels of crude / 1000 cubic feet. Reserve additions include the net of corrections and adjustments.

NA = Not available.

Sources: Industry data -- reserve additions: Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1982, 1983 and 1984 Annual Reports. Exploration and development expenditures: U.S. Department of Commerce, Annual Survey of Oil and Gas, 1982. Wells completed: special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information Administration's Monthly Energy Review, May 1985 (August 1985), p. 65. FRS companies data -- Form EIA-28.

Table G35. Domestic Net Ownership Interest[1] Petroleum Reserves and Production for FRS Companies and Domestic Industry, 1984

Reserves and Production	Crude Oil and Natural Gas Liquids (billion barrels)		Natural Gas (trillion cubic feet)	
	FRS Companies	Domestic Industry	FRS Companies	Domestic Industry
Onshore				
Beginning Reserves	18.2	31.4	83.8	162.7
Ending Reserves	18.6	31.8	83.5	159.0
Percent Change	2.4	1.3	-0.3	-2.3
Production	1.8	3.3	4.9	12.1
Percent Change from 1983	0.1	0.7	6.7	7.4
Offshore				
Beginning Reserves	2.6	4.3	24.3	37.5
Ending Reserves	2.7	4.3	23.8	38.5
Percent Change	2.2	1.2	-2.0	2.6
Production	0.3	0.5	3.1	5.1
Percent Change from 1983	9.0	9.6	9.9	12.6
Total				
Beginning Reserves	20.8	35.6	108.0	200.2
Ending Reserves	21.3	36.1	107.3	197.5
Percent Change	2.4	1.3	-0.7	-1.4
Production	2.1	3.8	7.9	17.2
Percent Change from 1983	1.4	1.8	7.9	8.9

[1]Net working interest plus royalty interest.

Sources: Industry data -- Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Report, 1983 and 1984. FRS companies data -- Form EIA-28.

Table G36. Foreign Crude Oil and Natural Gas Liquids Production for FRS Companies and Foreign Industry, 1984 and Percent Change from 1983

Foreign Crude Oil and Natural Gas Liquids Production	Total Foreign	Canada	OECD Europe	Africa	Middle East	Other Eastern Hemisphere	Other Western Hemisphere
FRS Companies[1]							
1984 (million barrels) . . .	1,338.7	192.0	441.1	275.4	107.0	196.9	126.2
1984 Distribution Percent. .	100.0	14.3	32.9	20.6	8.0	14.7	9.4
Percent Change from 1983 . .	9.4	3.3	11.2	3.2	19.2	22.7	1.9
Foreign Industry							
1984 (million barrels) . . .	12,010.6	648.6	1,407.2	1,869.9	4,369.0	1,261.2	2,454.7
1984 Distribution Percent. .	100.0	5.4	11.7	15.6	36.4	10.5	20.4
Percent Change from 1983 . .	3.7	-0.2	9.6	8.3	-1.5	11.4	4.3
FRS Companies as a Percent of Foreign Industry							
1984	11.1	29.6	31.3	14.7	2.4	15.6	5.1
1983	10.6	28.6	30.9	15.5	2.0	14.2	5.3
1982	9.9	29.2	29.1	17.5	1.8	13.0	5.3

[1]FRS foreign crude oil and natural gas liquids production defined as net ownership production plus foreign access.
Sources: Industry data -- Energy Information Administration, International Energy Annual, 1982, 1983 and 1984.
FRS companies data -- Form EIA-28.

Table G37. Distribution of Foreign Exploration and Development Expenditures for FRS Companies Ranked by Total Energy Assets, 1984 and Percent Change from 1983

Exploration and Development Expenditures	Total Foreign	Canada	OECD Europe	Africa and Mideast	Other Eastern Hemisphere	Other Western Hemisphere
	(million dollars)					
1984						
All FRS	17,277.6	5,379.2	5,466.0	3,858.3	2,031.8	543.1
Top Four	11,882.1	4,585.5	3,607.9	2,337.9	1,191.8	159.0
Five Through Twelve	3,063.7	607.8	721.1	1,076.5	351.3	307.0
All Other	2,331.7	185.9	1,137.0	443.9	487.8	77.1
	(percent)					
Distribution 1984						
All FRS	100.0	31.1	31.6	22.3	11.8	3.1
Top Four	100.0	38.6	30.4	19.7	10.0	1.3
Five Through Twelve	100.0	19.8	23.5	35.1	11.5	10.0
All Other	100.0	8.0	48.8	19.0	20.9	3.3
Change from 1983						
All FRS	61.6	229.6	28.3	79.7	-0.9	-10.3
Top Four	157.0	592.7	70.9	331.3	6.4	-15.6
Five Through Twelve	0.6	10.8	-7.3	2.3	0.1	-2.6
All Other	-22.9	-55.9	-17.0	-19.8	-15.6	-24.4

Source: Form EIA-28.

Table G38. Foreign Exploration and Development Wells Completed[1] for FRS Companies and Foreign Industry, 1984 and Percent Change from 1983

Wells Drilled	Total Foreign Wells	Total Foreign	Canada	OECD Europe	Africa and Mideast	Other[2]
		(percent)				
Total Wells						
FRS Companies						
1984	2,036.4	100.0	60.2	11.8	6.9	21.2
Change from 1983		23.8	34.6	19.5	0.8	9.0
Foreign Industry						
1984	16,718.0	100.0	57.2	6.0	5.4	31.4
Change from 1983		18.3	38.0	14.3	-13.9	-0.6
FRS as Percent of Foreign Industry						
1984		12.2	12.8	24.0	15.6	8.2
1983		11.6	13.1	22.9	13.3	7.5
Success Rate						
FRS Companies						
1984		72.9	74.6	65.6	66.0	74.6
1983		71.6	73.1	69.0	62.0	72.7
Foreign Industry						
1984		77.8	80.1	52.8	75.7	78.7
1983		78.9	81.2	62.0	78.5	78.7

[1]FRS data are net wells completed.
[2]Includes 'Other Eastern Hemisphere' and 'Other Western Hemisphere.'
Sources: Industry data -- 1983 - World Oil, August 15, 1984. 1984 - World Oil, August 15, 1985. FRS companies data -- Form EIA-28.

Table G39. Foreign Crude Oil and Natural Gas Liquids Reserve Interest for FRS Companies, 1984 and Percent Change from 1983

Crude Oil and NGL Reserves	Total Foreign	Canada	OECD Europe	Africa	Mideast	Other Eastern Hemisphere	Other Western Hemisphere
	(million barrels)						
1984 Total Crude and NGL Reserve Interest[1]	14,630.2	2,419.3	4,305.5	3,521.8	1,498.9	1,945.3	939.3
	(percent)						
Distribution, 1984 Total Crude and NGL Reserve Interest[1]	100.0	16.5	29.4	24.1	10.2	13.3	6.4
Percent Change from 1983 Total Crude and NGL Reserve Interest[1]	-0.9	10.0	-5.9	15.2	-26.3	-4.9	9.8

[1]The components of total foreign crude oil and natural gas liquids reserve interest are net ownership interest reserves (89.8 percent) and 'Other Access' reserves (10.2 percent). 'Other Access' reserves include proportional interest in investee reserves and foreign access reserves.

Source: Form EIA-28.

Table G40. Sources of Domestic Bituminous Coal and Lignite Supply for FRS Companies and Domestic Industry, 1983 and 1984

Supply	Domestic Production[1]	Imports	Domestic Purchases	Total
	(millions of tons)			
FRS Companies				
1984	226.0	0.0	11.0	237.0
1983	185.2	0.0	7.6	192.8
Percent Change	22.0	0.0	45.6	22.9
Domestic Industry				
1984	891.8	1.3	(2)	893.1
1983	778.0	1.3	(2)	779.3
Percent Change	14.6	0.0	(2)	14.6
FRS as a Percent of Domestic Industry				
1984	25.3	0.0	(2)	26.5
1983	23.8	0.0	(2)	24.7

[1]Includes captive and noncaptive production.
[2]Not meaningful.
Sources: Industry data -- Energy Information, Administration, Weekly Coal Production, July 6, 1985.
FRS companies -- Form EIA-28.

Table G41. Sources of Domestic Bituminous Coal and Lignite Production, by Region and Mining Method, for FRS Companies and Domestic Industry, 1984 and Percent Change from 1983

Production[1]	Total	East	Midwest	West
	(million tons)			
1984				
FRS Companies				
Underground	91.2	64.7	19.4	7.1
Surface	134.8	16.8	18.6	99.4
Total	226.0	81.4	38.0	106.5
Domestic Industry				
Total	891.8	439.9	143.7	308.2
	(percent)			
Distribution by Region, 1984				
FRS Companies				
Underground	100.0	70.9	21.3	7.8
Surface	100.0	12.4	13.8	73.8
Total	100.0	36.0	16.8	47.1
Domestic Industry				
Total	100.0	49.3	16.1	34.6
Distribution by Mining Method, 1984				
FRS Companies				
Underground	40.4	79.4	51.1	6.7
Surface	59.6	20.6	48.9	93.3
Total	100.0	100.0	100.0	100.0
FRS Companies as a Percent of Domestic Industry Total	25.3	18.5	26.4	34.6
Change from 1983				
FRS Companies				
Underground	24.1	18.8	53.4	11.3
Surface	20.6	-7.1	17.2	27.7
Total	22.0	12.3	33.3	26.5
Domestic Industry				
Total	14.6	16.1	15.6	12.2

[1]Includes captive and noncaptive production.

Sources: Industry data -- Energy Information Administration, Weekly Coal Production, July 6, 1985. FRS companies data -- Form EIA-28.

Table G42. Domestic Dispositions of Bituminous Coal and Lignite for FRS Companies and Domestic Industry, 1984 and Percent Change from 1983

Dispositions	Total Dispositions	Electric Utilities	Steel Companies	All Other Domestic[1]	Exports
	(million tons)				
1984					
FRS Companies	220.5	183.0	12.5	12.7	12.3
Domestic Industry	885.4	680.0	43.7	81.7	79.9
	(percent)				
Distribution, 1984					
FRS Companies	100.0	83.0	5.7	5.7	5.6
Domestic Industry	100.0	76.8	4.9	9.2	9.0
FRS as a Percent of Domestic Industry	24.9	26.9	28.6	15.5	15.4
Change from 1983					
FRS Companies	19.2	23.2	16.2	16.6	-16.6
Domestic Industry	12.8	13.8	16.8	12.1	4.0

[1]Other industrial, residential, commercial, and institutional, and for FRS companies, sales to domestic unconsolidated affiliates.

Sources: Industry data -- Energy Information Administration, Coal Distribution January - December 1983 (April 1984) p. 12, and Coal Distribution January - December 1984 (April 2, 1985) p. 10. FRS companies data -- Form EIA-28.

Table G43. Domestic Uranium Production and Estimated Uranium Reserves for FRS Companies and Domestic Industry, 1983 and 1984

(Million Pounds U_3O_8)

Production and Reserves	Production	Estimated Reserves[1]		
		$30	$50	$100
FRS Companies				
1984	4.1	NA	NA	NA
1983	6.6	NA	NA	NA
Percent Change	-37.9	NA	NA	NA
Domestic Industry				
1984	13.6	359.0	1,106.0	1,719.0
1983	23.5	360.0	1,140.0	1,770.0
Percent Change	-42.1	-0.3	-3.0	-2.9
FRS as a Percent of Domestic Industry				
1984	30.1	NA	NA	NA
1983	28.1	NA	NA	NA

[1]Reserves estimates are based upon forward costs of production. Forward costs comprise operating and capital costs, including costs of labor, materials, electricity, royalties, payroll and production taxes, insurance, and applicable general and administrative costs and exclude previous expenditures for such items as property acquisition, exploration, mine development, mill construction, income taxes, profit, and the cost of money. The various cost categories are independent of the market price at which the uranium would be sold.

NA=Not available.

Sources: FRS companies' production: Form EIA-28. Industry production and reserves: Energy Information Administration, Uranium Industry Annual 1984 (October 1985).

Table G44. Domestic Uranium Resource Development Measures and Drilling Expenditures for FRS Companies and Domestic Industry, 1984 and Percent Change from 1983

Measures and Expenditures	FRS Companies		Domestic Industry		FRS as a Percent of Domestic Industry
	1984	Percent Change from 1983	1984	Percent Change from 1983	
Land Held for Exploration (million acres)					
Acquired	0.4	W	0.5	0.0	80.0
Held (end of year)	1.1	21.3	3.4	-26.1	32.4
Surface Drilling Footage (million feet)					
Exploration	W	W	2.3	9.5	W
Development	W	W	0.3	-72.7	W
Total	0.4	22.0	2.6	-18.8	15.4
Expenditures (million dollars)					
Exploratory Drilling	W	W	10.5	-0.9	W
Development Drilling	W	W	1.3	-65.8	W
Total	1.3	-29.5	11.8	-18.1	11.0

W=Data withheld to avoid disclosure.
Sources: Industry data -- Energy Information Administration, Uranium Industry Annual 1984 (October 1985).
FRS companies data -- Form EIA-28.

Table G45. Other Energy: Patterns of Income and Investment for FRS Companies, 1983 and 1984

Income and Investment	Total Foreign	Domestic[1]				
		Total Domestic	Oil Shale	Geothermal	Coal Gasification/ Liquefaction and Tar Sands	Solar and Other
	(million dollars)					
Contributions to Income						
1984						
Operating Income	196.5	-394.4	-	-	-	-
Net Income	61.5	-68.0	-	-	-	-
1983						
Operating Income	205.8	-436.5	-	-	-	-
Net Income	92.4	-51.5	-	-	-	-
Investment Patterns						
1984						
Net PP&E[2]	1,132.0	2,581.2	1,561.2	749.9	55.5	214.6
Additions to PP&E	172.2	651.8	36.6	578.0	2.0	35.2
R&D Expenditures[2,3]	375.9		106.5	([4])	129.0	140.4
	(percent)					
Distribution, 1984						
Net PP&E[2]		100.0	60.5	29.1	2.2	8.3
Additions to PP&E		100.0	5.6	88.7	0.3	5.4
R&D Expenditures[3]	100.0		28.3	([4])	34.3	37.4
Change from 1983						
Net PP&E[2]	-2.2	5.8	-9.1	83.9	8.3	-18.5
Additions to PP&E	-3.1	36.2	-81.6	298.6	-78.4	-71.9
R&D Expenditures[3]	-3.0		16.9	([4])	-32.0	31.3

[1]Income data for domestic segments not collected after 1980.
[2]Breakdown of domestic other energy will not sum to total domestic because eliminations and nontraceables are not included in the table.
[3]Research and development (R&D) total expenditures are worldwide.
[4]Geothermal research and development expenditures included in Solar and Other to prevent disclosure.
- = Not disclosable.
Source: Form EIA-28.

Table G46. Uses of Research and Development Funds[1] for FRS Companies, 1984 and Percent Change from 1983

Research and Development Expenditures	Total	Petroleum	Coal		Nuclear	Other Energy[2]	Non-Energy	Unassigned
			Conventional	Gasification/ Liquefaction				
	(million dollars)							
1984 Total.	4,063.8	1,306.8	34.7	102.2	95.1	273.7	2,157.3	94.0
	(percent)							
Distribution, 1984 Total.	100.0	32.2	0.9	2.5	2.3	6.7	53.1	2.3
Change from 1983 Total.	6.6	5.1	3.4	-35.7	7.1	19.7	9.5	6.4

[1]Research and development expenditures shown here include both expensed and capitalized items. Overall, expensed items account for 90.8 percent and capitalized expenditures for 9.2 percent of total research and development funds.
[2]Does not include coal gasification and liquefaction.
Source: Form EIA-28.

Table G47. Sources of Research and Development (R&D) Funds for FRS Companies Ranked by Total Energy Assets, 1984 and Percent Change from 1983

Sources	1984	Percent Change from 1983	Percent Distribution 1984
	(million dollars)	(percent)	
Total R&D			
Top Four	1,432.5	6.1	35.3
Five Through Twelve	1,120.8	5.6	27.6
All Other	1,510.5	7.8	37.2
All FRS	4,063.8	6.6	100.0
Sources of R&D			
Federal	104.2	11.9	2.6
Internal Company	3,945.0	6.9	97.1
Other Sources	14.6	-46.8	0.4
Total	4,063.8	6.6	100.0

Source: Form EIA-28.

Table G48. Domestic and Foreign Oil Raw Materials Balance for FRS Companies Ranked by Total Energy Assets, 1982 to 1984

(Million Barrels)

Geographical Sector	Raw Material Acquistions				
	Direct Oil Access[1]	Net Oil Purchases[2]	Net Oil Imports	Oil Stock Changes[3]	Total Refinery Input
Domestic					
All FRS					
1984	2,076.1	741.0	876.2	61.0	3,754.2
1983	2,097.8	676.5	818.7	55.2	3,648.3
1982	2,125.8	526.6	990.3	76.7	3,719.4
Top Four					
1984	749.3	190.7	309.9	1.2	1,251.1
1983	643.7	207.8	268.4	34.8	1,154.8
1982	655.0	123.8	369.4	27.7	1,175.9
Five Through Twelve					
1984	1,031.5	69.3	306.9	24.9	1,432.6
1983	1,082.9	14.2	287.8	20.5	1,405.4
1982	1,090.2	12.7	305.9	20.4	1,429.2
All Other					
1984	295.3	480.9	259.4	34.9	1,070.5
1983	371.2	454.6	262.4	-0.1	1,088.1
1982	380.6	390.2	315.1	28.5	1,114.4
Foreign					
All FRS					
1984	1,796.7	531.2	-876.2	38.2	1,489.9
1983	1,857.0	436.8	-818.7	77.3	1,552.5
1982	2,455.1	262.1	-990.3	73.6	1,800.6
Top Four					
1984	1,117.9	382.8	-309.9	43.9	1,234.6
1983	1,278.6	241.0	-268.4	24.2	1,275.4
1982	1,868.1	-34.7	-369.4	49.9	1,513.9
All Other[4]					
1984	678.7	148.4	-566.2	-5.7	255.3
1983	578.4	195.8	-550.2	53.1	277.2
1982	587.0	296.9	-620.9	23.7	286.6

[1]Ownership interest production plus purchases from other company segments and from unconsolidated affiliates of crude oil and natural gas liquids (domestic and foreign areas) plus foreign access oil (foreign area only). Foreign access represents acquistions from foreign entities, for which reporting firms act as producers under long-term contract.

[2]Purchases of crude and natural gas liquids (except imports) on the open market or from unaffiliated third parties less oil sales to unaffiliated third parties.

[3]Positive number indicates stock withdrawal (addition to supply).

[4]The 'Five Through Twelve' and 'All Other' groups combined into foreign 'All Other' to prevent disclosure.

Source: Form EIA-28.

Table G49. Domestic Refinery Output, and Refinery Capacity Statistics[1], for FRS Companies Ranked by Total Energy Assets and Domestic Industry, 1983 and 1984

(Thousand Barrels per Day)

Refined Product Statistics 1983 And 1984	FRS Companies				U.S. Industry	FRS Percent of Industry
	All FRS	Top Four	Five Through Twelve	All Other		
1984						
Refinery Output Volume[2]	10,996	3,594	4,361	3,041	14,171	77.6
Percent Gasoline	47.0	46.7	48.2	45.5	46.5	78.4
Percent Distillate	25.5	24.2	24.2	28.9	27.1	73.0
Percent Other	27.5	29.1	27.6	25.6	26.4	80.9
Refinery Capacity						
Year's Change (Net)	-243	122	58	-423	-448	54.2
At Year End	12,771	4,494	4,639	3,638	16,325	78.2
Utilization Rate[3]	79.5	78.6	85.6	73.4	75.4	(4)
1983						
Refinery Output Volume[2]	10,378	3,278	3,965	3,135	13,585	76.4
Percent Gasoline	49.0	46.3	52.5	47.3	47.7	78.5
Percent Distillate	23.5	22.4	22.1	26.5	25.7	70.0
Percent Other	27.5	31.4	25.4	26.1	26.7	78.8
Refinery Capacity						
Year's Change (Net)	-626	-95	-467	-64	-846	74.0
At Year End	13,014	4,372	4,581	4,061	16,773	77.6
Utilization Rate[3]	73.9	69.6	79.4	72.2	70.3	(4)

[1]Domestic FRS and domestic industry data include operations in Puerto Rico and the U.S. Virgin Islands.
[2]For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.
[3]Defined as average daily crude runs at own refineries, for own account and for account of others, divided by average daily crude distillation capacity.
[4]Not meaningful.
Note: Sum of components may not equal total due to independent rounding.
Sources: Industry data -- Refinery output: Data compiled for the International Energy Agency by the Petroleum Supply Division, Office of Oil and Gas, Energy Information Administration. Refinery capacity: Energy Information Administration, Petroleum Supply Annual, 1983 and 1984. FRS companies data -- Form EIA-28.

Table G50. Foreign Refinery Output, and Refinery Capacity Statistics[1], for FRS Companies Ranked by Total Energy Assets and Foreign Industry, 1983 and 1984

(Thousand Barrels per Day)

Refined Product Statistics 1983 and 1984	FRS Companies				
	All FRS	Top Four	All Other[2]	Foreign Industry	FRS Percent of Industry
1984					
Refinery Output Volume[3]	4,696	3,957	739	NA	([5])
Percent Gasoline	27.2	25.3	37.1	NA	([5])
Percent Distillate	34.9	34.5	37.2	NA	([5])
Percent Other	37.9	40.2	25.7	NA	([5])
Refinery Capacity					
Year's Change (net)	-185	-89	-96	-136	136.0
At Year End	6,272	5,424	848	41,291	15.2
Utilization Rate[4]	61.2	58.6	77.0	NA	([5])
1983					
Refinery Output Volume[3]	5,000	4,101	899	30,474	16.4
Percent Gasoline	26.3	24.8	33.0	19.9	21.6
Percent Distillate	35.4	34.7	39.0	30.6	19.0
Percent Other	38.3	40.5	27.9	49.5	12.7
Refinery Capacity					
Year's Change (net)	-797	-543	-254	-1,288	61.9
At Year End	6,457	5,513	944	41,427	15.6
Utilization Rate[4]	59.5	57.3	71.1	72.4	([5])

[1]Foreign FRS and foreign industry data exclude operations in Puerto Rico and the U.S. Virgin Islands, as well as China and the Soviet Bloc.
[2]'Five through Twelve' and 'All Other' groups combined to avoid disclosure.
[3]For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.
[4]Defined as average daily crude runs at own refineries, for own account and for account of others, divided by average daily crude distillation capacity.
[5]Not meaningful.
NA = Not available.
Note: Sum of components may not equal total due to independent rounding.
Sources: Industry data -- Energy Information Administration, International Energy Annual, 1983 and 1984. FRS companies data -- Form EIA-28.

Table G51. Domestic Refined Petroleum Product Sales Volumes[1] and Values[2], by Distribution Channel for FRS Companies, 1983 and 1984

Distribution Channel	Total		Gasoline		Distillate Fuels		All Other Products	
	Volume	Value	Volume	Value	Volume	Value	Volume	Value
1984								
Domestic Intra-Company	263.8	7,747.3	5.9	201.6	15.4	490.5	242.5	7,055.2
Wholesale/Resellers	1,891.9	64,324.4	993.1	34,247.3	570.8	19,319.1	328.0	10,758.0
Total Retail Automotive Outlets	1,036.2	38,728.9	980.5	36,497.3	50.5	1,831.8	5.1	399.8
Other[3]	1,220.7	39,551.0	115.6	4,043.9	569.2	19,801.5	535.9	15,705.7
Total	4,412.6	150,351.6	2,095.1	74,990.1	1,206.0	41,442.8	1,111.5	33,918.8
1983								
Domestic Intra-Company	220.3	6,528.9	6.6	241.1	14.7	494.4	199.0	5,793.4
Wholesale/Resellers	1,786.6	63,314.2	955.8	35,451.0	517.7	17,945.9	313.1	9,917.2
Total Retail Automotive Outlets	1,005.2	39,435.0	949.0	37,160.3	48.7	1,790.5	7.4	484.2
Other[3]	1,225.9	40,592.4	132.2	4,882.2	548.6	19,724.3	545.1	15,985.8
Total	4,237.9	149,870.4	2,043.5	77,734.6	1,129.7	39,955.1	1,064.6	32,180.7

[1]Volume = Million barrels.
[2]Value =Million dollars.
[3]Includes direct sales to industrial and commercial users and sales to unconsolidated affiliates.
Source: Form EIA-28.

Table G52. Sales of Domestic Refined Petroleum Products, by Volume[1] and Price[2], for FRS Companies, 1983 and 1984

Distribution Channel	Total		Gasoline		Distillate		All Other Products	
	Volume	Price	Volume	Price	Volume	Price	Volume	Price
Intra-Company Sales								
1984	263.8	29.37	5.9	34.42	15.4	31.79	242.5	29.10
1983	220.3	29.64	6.6	36.54	14.7	33.74	199.0	29.11
Percent Change	19.8	-0.9	-11.2	-5.8	5.3	-5.8	21.8	-0.1
Wholesale/Resellers								
1984	1,891.9	34.00	993.1	34.49	570.8	33.85	328.0	32.80
1983	1,786.6	35.44	955.8	37.09	517.7	34.66	313.1	31.68
Percent Change	5.9	-4.1	3.9	-7.0	10.3	-2.4	4.8	3.5
Retail Automotive Outlets								
1984	1,036.2	37.38	980.5	37.22	50.5	36.26	5.1	78.49
1983	1,005.2	39.23	949.0	39.16	48.7	36.74	7.4	65.13
Percent Change	3.1	-4.7	3.3	-4.9	3.7	-1.3	-31.5	20.5
Other[3]								
1984	1,220.7	32.40	115.6	34.98	569.2	34.79	535.9	29.31
1983	1,225.9	33.11	132.2	36.94	548.6	35.95	545.1	29.33
Percent Change	-0.4	-2.2	-12.5	-5.3	3.8	-3.2	-1.7	-0.1
Total								
1984	4,412.6	34.07	2,095.1	35.79	1,206.0	34.37	1,111.5	30.52
1983	4,237.9	35.36	2,043.5	38.04	1,129.7	35.37	1,064.6	30.23
Percent Change	4.1	-3.7	2.5	-5.9	6.7	-2.8	4.4	1.0

[1]Volume = Million barrels.
[2]Price = Dollars per barrel.
[3]Includes direct sales to industrial and commercial users and sales to unconsolidated affiliates.
Source: Form EIA-28.

Table G53. Domestic Gasoline Sales for FRS Companies Ranked by Total Energy Assets, 1983 and 1984

Distribution Channel	All FRS		Top Four		Five Through Twelve		All Other	
	1983	1984	1983	1984	1983	1984	1983	1984
	(percent of value shipped)							
Percent Total Value								
Total Domestic	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Third Parties	45.7	45.8	41.6	41.7	36.6	36.7	62.6	63.9
Wholesale/ Resellers	14.8	14.6	14.0	11.5	13.1	13.8	18.0	19.2
Company Operated Automotive Outlets[1]	33.1	34.2	38.3	41.1	44.9	44.7	11.5	10.9
Lessee and Open Dealer Automotive Outlets[1]	6.3	5.4	6.1	5.6	5.3	4.9	7.9	6.0
Other								
	(dollars per barrel)							
Average Price								
Total Domestic	38.04	35.80	38.92	35.62	38.01	36.06	37.23	35.62
Third Parties	37.09	34.49	38.33	34.32	36.62	34.41	36.67	34.67
Wholesale/ Resellers	41.48	39.64	42.61	38.51	42.69	41.33	39.52	38.74
Company Operated Automotive Outlets[1]	38.20	36.28	38.32	36.14	38.09	36.12	38.40	37.94
Lessee and Open Dealer Automotive Outlets[1]	36.94	34.98	39.13	36.43	37.09	35.46	35.26	33.03
Other								

[1]Categories not reported seperately before 1981.
Note: Sum of components may not add to total due to independent rounding.
Source: Form EIA-28.

Table G54. Domestic Refining/Marketing Revenues and Costs for FRS Companies, 1982 to 1984

Revenues and Costs	1982	1983	1984	1982	1983	1984
	Million Dollars			Percent of Product Revenues		
Refined Product Revenues	162,733.0	149,870.4	150,351.6	100.0	100.0	100.0
Refined Product Costs						
Raw Materials Processed[1]	114,366.0	101,653.3	104,031.4	70.3	67.8	69.2
Refinery Energy Expense	8,936.0	8,837.2	8,664.1	5.5	5.9	5.8
Other Refinery Expense	7,491.6	6,351.5	7,038.4	4.6	4.2	4.7
Product Purchases[2]	18,332.0	20,175.9	20,237.6	11.3	13.5	13.5
Other Product Supply Expense	3,369.5	3,244.3	2,160.1	2.1	2.2	1.4
Marketing Expense[3]	6,613.0	6,595.4	8,187.7	4.1	4.4	5.4
Total Refined Product Costs	159,108.1	146,857.6	150,319.4	97.8	98.0	100.0
Refined Product Margin	3,625.0	3,012.8	32.2	2.2	2.0	0.0
Dollars per Barrel Margin[4]	0.85	0.71	0.01			
Other Refining/Marketing Revenues[5]	5,553.0	5,104.2	5,733.0			
Other Refining/Marketing Expenses						
DD&A	2,194.3	2,187.4	2,392.5			
Other[6]	4,706.3	4,457.0	4,399.0			
Total Other Expenses	6,900.6	6,644.4	6,791.5			
Refining/Marketing Operating Income	2,277.3	1,472.6	-1,026.3			
Income Taxes and Miscellaneous	364.0	-163.2	-1,131.2			
Refining/Marketing Net Income	1,913.3	1,635.9	104.8			

[1]Represents reported cost of raw materials processed at refineries, less any profit from raw material trades or exchanges by refining/marketing. Includes DOE crude entitlements before 1982.
[2]Includes DOE residual fuel entitlements before 1982.
[3]Excludes cost of marketing tires, batteries, and accessories (TBA).
[4]Dollars per barrel of refined product sold.
[5]Includes revenues from transportation services supplied (non-federally regulated), TBA sales and miscellaneous.
[6]Includes general and administrative expenses, research and development costs, costs of transportation services supplied to others not included in raw material costs, and expenses for TBA.
Source: Form EIA-28.

Table G55. Annual Percent Change in Net Property, Plant, and Equipment in Domestic Refining/Marketing Compared to Other Domestic Petroleum for FRS Companies Ranked by Total Energy Assets, 1981 to 1984

Company Groups	Refining/Marketing								Other Petroleum[1]	
	Total		Refining		Marketing		R/M Transport			
	1984	1981-1984 Average	1984	1981-1984 Average	1984	1981-1984 Average	1984	1981-1984 Average	1984	1981-1984 Average
Domestic										
All FRS.	2.4	6.0	0.5	7.7	10.7	4.8	-4.5	0.6	12.1	14.3
Top Four	19.7	18.1	13.4	19.2	40.4	18.1	1.8	10.6	58.8	32.1
Five Through Twelve. . . .	-8.8	-1.0	-7.5	2.1	-14.2	-5.7	-3.3	-3.6	-2.5	5.6
All Other.	-6.9	1.1	-7.2	1.7	-1.7	0.9	-11.9	-1.7	-11.7	11.4

[1]Includes domestic production segment and domestic rate regulated pipeline segment. The production segment accounted for 91.4 percent of the net PP&E in this category in 1984.
Source: Form EIA-28.

Appendix H

Major Energy Provisions of the Tax Reform Act of 1984

Appendix H

Major Energy Provisions of the Tax Reform Act of 1984

The Deficit Reduction Act of 1984 became law in July 1984. Its objective is to reduce the Federal budget deficit. The Act has two major parts. One part is referred to as the Spending Reduction Act of 1984, which is intended to reduce the deficit by curtailing expenditures. The other is referred to as the Tax Reform Act of 1984, which reduces the deficit principally through tax increases and equivalent measures.

The Tax Reform Act of 1984 (referred to below as "the Act") contains a wide variety of essentially unrelated provisions. Although the Act is not energy-oriented, some of its provisions are energy-specific. The most important of these energy provisions are described below.

Roughly, 20 percent of all oil produced in the United States in 1984 is estimated to have been new oil subject to the WPT.[1] The WPT rate on this oil was 22.5 percent in 1984 and had been scheduled to fall to 20 percent for 1985 and to 15 percent for subsequent years. In order to generate additional tax revenues, the Act delays the scheduled reduction. Specifically, the Act retains the 22.5-percent rate through 1987, reduces the rate to 20 percent in 1988, and provides for a 15-percent rate in 1989 and thereafter.

The effects of the higher rates on WPT liabilities is likely to be quite small since the liability per taxable barrel of new oil had already fallen to an estimated $0.35 per barrel for the fourth quarter of 1984. The likely continued weakness in crude oil prices during the near future combined with continued increases in the inflation (and severance tax) adjusted base price would substantially eliminate WPT liabilities on new oil in the near future even with the high WPT rates.

Another provision of the Act relates to percentage depletion. Percentage depletion can be used by certain "independents" among oil and gas producers to calculate capital consumption allowances for up to 1,000 barrels per day of crude-oil-equivalent production. However, their use of this method for secondary and tertiary production ended at the end of 1983 as a result of a technical error in legislation enacted 8 years earlier. The Tax Reform Act of 1984 corrects this error, limits the termination to secondary and tertiary production from proven properties transferred after 1974, and assigns the same depletion rate (15 percent of the gross income from the property) to secondary and tertiary production as applies to primary production. These measures became retroactively effective to the beginning of 1984.

The Act increases the share of intangible drilling and development costs that the integrated oil companies must capitalize from 15 percent to 20 percent. The increase is effective for expenditures made during tax years beginning on or after January 1, 1985.

The Act alters the method for calculating "earnings and profits" for dividend payment purposes. Distributions by corporations to shareholders are generally taxable as dividends only to the extent that they are paid out of current or accumulated "earnings and profits," as defined for tax purposes. To bring the tax definition into greater conformity with relevant economic definitions, the

Act requires that corporations make several changes in the way in which they calculate these earnings and profits. Generally, the changes do not distinguish between the types of activities in which corporations engage. However, two changes do distinguish between activity types. These changes apply to deductible intangible drilling costs and to deductible mineral exploration and development costs. The Act requires that these expenditures (other than costs incurred in connection with a nonproductive well) be treated as if they had been capitalized if they result in the creation of an asset having a life expectancy of more than 1 year. The capitalized intangible drilling costs must be amortized over a 5-year period and the capitalized mineral exploration and development costs over a 10-year period. These changes will alter the potential time profile over which dividends can be distributed since the time profile over which "earnings and profits" are acquired will change. However, the time profile of actual distributions will not likely be significantly affected. Generally, these changes, as well as those that do not distinguish among the activities of corporations, became effective for taxable years beginning after September 30, 1984.

The Act replaces the Domestic International Sales Corporation (DISC) system of tax aids for exports with a Foreign Sales Corporation (FSC) system. DISC had been introduced in the early 1970s as an incentive to export U.S.-produced goods by deferring U.S. taxes on part of the selling profit of a DISC for an indeterminate period. The Act replaced DISC with FSC (subject to exceptions) in order to overcome objections by U.S. trade partners that DISC involved subsidies prohibited by the General Agreement on Tariffs and Trade. To qualify as a FSC, export sales must be made through a company incorporated outside U.S. territory, in contrast to a DISC, which was incorporated in the United States. A number of other requirements must also be met to qualify as a FSC. Generally, the Act retains DISC benefits in modified form by exempting a portion of FSC export income from U.S. tax. From an energy perspective, the most important change is that the export of depletable products, such as coal (but not oil and gas), qualify for FSC benefits. The law that had originally allowed DISCs to be created had granted DISC treatment to the export of natural resources. However, a 1975 Act denied such treatment to natural resource products that were subject to percentage depletion allowances, such as oil, gas, and coal. The Tax Reform Act of 1984 generally reinstituted the original treatment, except for oil and gas and primary products thereof. Generally, the DISC provision of the Act applies to transactions after December 31, 1984, but there are exceptions.

Prior to the Act, royalty payments between parties that owned coal reserves and others who mined them were accorded capital gains treatment. The Act prohibits this favorable tax treatment between related parties after September 30, 1985, but exceptions apply for certain coal sold through 1989.

Another provision of the Act applies to nuclear decommissioning costs. A general principle of the accrual method of accounting under the Act is that taxpayers should only deduct liabilities when the activities that give rise to them are performed.[2] The Act allows utility companies that own nuclear power plants to deviate from this principle by taking current deductions for contributions to reserve funds to meet future plant close down costs, to the extent that such contributions are reflected in service costs, charges to customers, and taxable income. Also, operating losses that result from closing nuclear plants may be

carried back, under certain circumstances, to earlier taxable years during which the plant was in operation.

A provision similar to that for nuclear decommissioning costs applies to certain other costs. These are the estimated future costs of certain mining and waste disposal site (other than a "Superfund" site) reclamation and closing activities that are expected to be attributable to current production or mining activity. The Act allows these costs to be currently deducted even though they will not be incurred until a later date. This provision of the Act also applies to coal mining.

Several provisions of the Act relate to the taxation of motor fuels. Perhaps the most important of these[3] is the excise tax on the sale of diesel fuel for use in highway vehicles. This tax was increased from 9 cents a gallon to 15 cents a gallon beginning in August 1984. The increase is fully rebated (in the form of an advance income tax credit of specified value) for new or recent diesel-powered highway vehicles below a certain weight (which includes all diesel-powered automobiles and small trucks) and partially rebated for certain older diesel vehicles.

Footnotes to Appendix H

[1]New oil is oil sold after May 31, 1979 and produced from an onshore property developed after 1978, or from an offshore area leased after January 1, 1979 and from which there was no production in 1978.

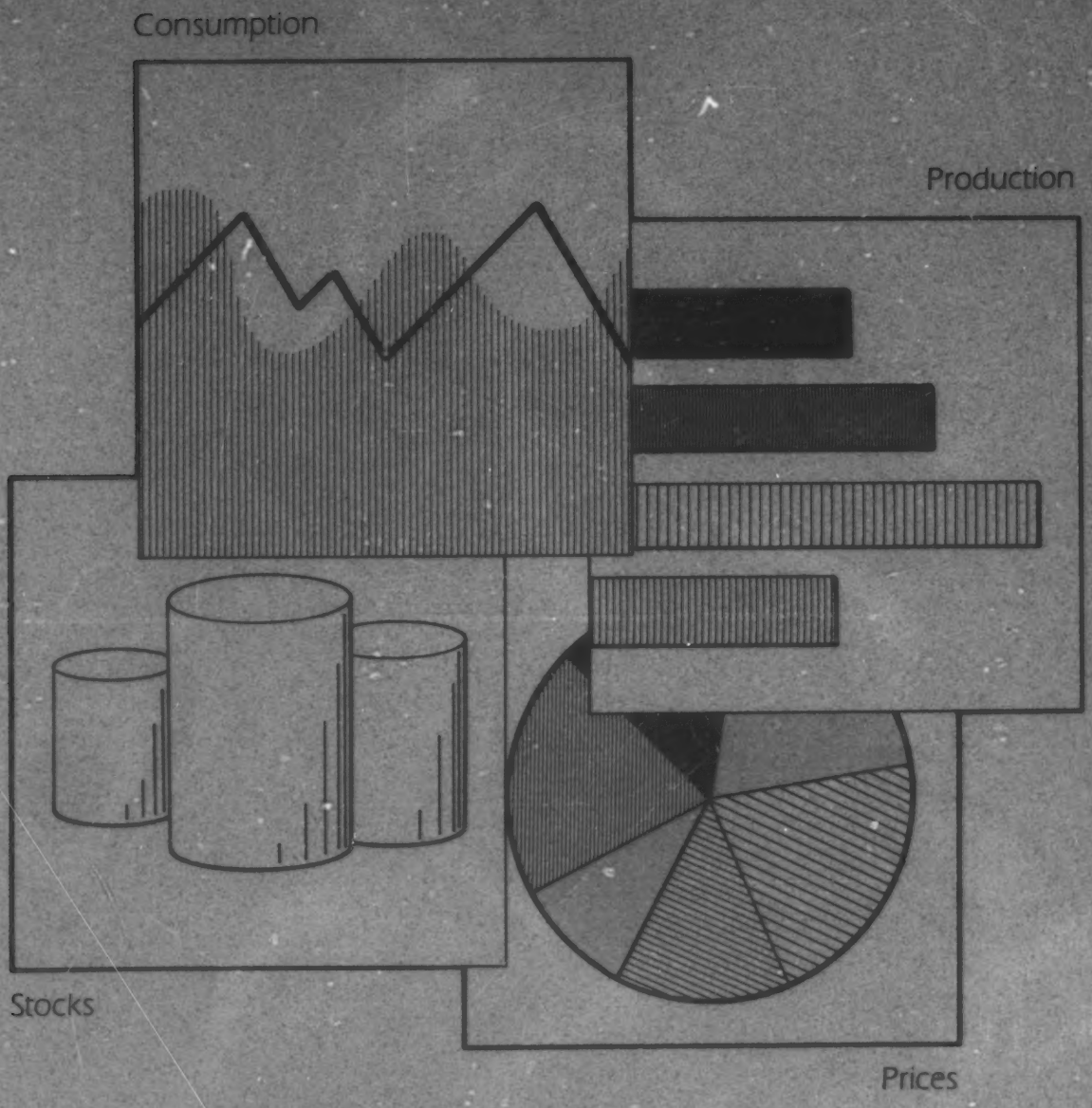
[2]This requirement of the Act is more stringent than prior law.

[3]Several of the other changes apply to taxes on alcohol and alcohol fuels. Also, two provisions, that are not restricted to diesel fuels or to alcohol fuels, relate to taxicabs and helicopters. First, the Act extends for 1 year, through September 1985, the period for which certain taxicabs rated at above-average fuel economy are exempt from 4 cents per gallon of the excise tax on gasoline as well as on diesel fuel and special motor fuels. Second, the Act grants to helicopters engaged in oil and gas exploration the same exemptions from fuel and certain other taxes that have been in force for helicopters used in certain timber and hard minerals operations.

*U.S. GOVERNMENT PRINTING OFFICE: 1986-491-163:20103

Looking for Energy Information?

The Energy Information Administration has Data and Projections on:



Contact:

Energy Information Administration
National Energy Information Center
Forrestal Building, 1F-048
1000 Independence Avenue, S.W.
Washington, D.C. 20585
(202) 252-8800

Energy Information Administration
Forrestal Building
Washington, DC 20585

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

FIRST—CLASS MAIL
POSTAGE & FEES PAID
U.S. DEPT. OF ENERGY
PERMIT NO. G 20

FIRST CLASS MAIL